

**MINNKOTA POWER COOPERATIVE, Inc. and
SQUARE BUTTE ELECTRIC COOPERATIVE**

**RESPONSES TO COMMENTS TO
NDDH REGARDING REVISED DRAFT NO_x BACT DETERMINATION and
NORTH DAKOTA STATE IMPLEMENTATION PLAN for REGIONAL HAZE
MILTON R. YOUNG STATION UNIT 1 and UNIT 2**

July 30, 2010

North Dakota Department of Health's Environmental Health Section, Division of Air Quality has informed Minnkota Power Cooperative Inc. ("Minnkota" or "MPC") of the opportunity to respond¹ to comments submitted by the United States Environmental Protection Agency (U.S. EPA or EPA)², National Park Service (NPS)³, and National Parks Conservation Association (NPCA)⁴ following NDDH's issuance of a revised draft Best Available Control Technology (BACT) Determination⁵ and NDDH's Regional Haze State Implementation Plan (RH SIP) involving the Best Available Retrofit Technology (BART) determination⁶ for control of nitrogen oxides (NO_x) emissions from existing Unit 1 and Unit 2 boilers at Milton R. Young Station (MRYS).

Burns & McDonnell (B&McD) was retained by MPC as an independent consultant to perform the referenced 2006 NO_x BACT Analysis Study⁷ of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station in accordance with the requirements of a Consent Decree (CD)⁸. Burns & McDonnell also performed the November 2009 Supplemental NO_x BACT Analysis Study⁹ and generated the referenced reports for each MRYS boiler in response to the NDDH's request¹⁰ to see Steps 3 and 4 of the BACT analysis process¹¹ include low-dust and tail end selective catalytic reduction (SCR) alternatives, assuming that they are technically feasible to apply at MRYS as NDDH has previously stated¹². Minnkota provided additional information supplementing the November

¹ See Reference number 1, May 12, 2010*.

² See Reference number 2, May 10, 2010*.

³ See Reference number 3, May 10, 2010.

⁴ See Reference number 4, January 8, 2010*.

⁵ See Reference number 5, April 6, 2010*.

⁶ See Reference number 6, November 25, 2009*.

⁷ See Reference number 7, October 2006*.

⁸ See Reference number 8, April 24, 2006.

⁹ See Reference number 9, November 12, 2009*.

¹⁰ See Reference number 10, July 15, 2009*.

¹¹ See Reference number 11, October 1990.

¹² Ibid Reference number 5, April 6, 2010*.

* SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NO_x BACT/BART Analysis Study reports and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NO_x BACT Analysis Study reports and subsequent responses.

2009 Supplemental NO_x BACT Analysis Study as requested by the NDDH^{13,14}, which included detailed breakdown of capital costs and operation and maintenance costs for hypothetical applications of low-dust and tail end SCR alternatives¹⁵, and their subsequent presentation to NDDH¹⁶, as performed by Burns & McDonnell, in December, 2009, and February, 2010¹⁷. A BART Analysis Study incorporating information developed in the referenced 2006 NO_x BACT Analysis Study was also performed for Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station by Burns & McDonnell in 2006¹⁸.

These responses regarding selective catalytic reduction (SCR) technology pertain to the NDDH's draft NO_x BACT Determination for Nitrogen Oxides for Milton R. Young Station Units 1 and 2, dated April, 2010 (NDDH, 2010). We continue to believe that the administrative record fully supports a finding by the North Dakota Department of Health ("NDDH") that separated over-fire air (SOFA) in conjunction with selective non-catalytic reduction (SNCR) technology is Best Available Control Technology for electric generating units that utilize cyclone burners firing North Dakota lignite. The following sections address specific topics discussed in the EPA's comments and in a separate report written by the United States Department of Justice's (DOJ's) SCR consultant and other commenters' submitted comments in greater detail.

- Responses to May 2010 EPA Comments on NO_x BACT Determination for Milton R. Young Station
 - EPA's NSR Workshop Manual and Office of Air Quality Planning and Standards (OAQPS) Control Cost Manual for Calculating SCR Control Cost Effectiveness
 - Responses to EPA Comments on SCR Annual Cost Estimates and Methods
 - Responses to EPA Comments on SCR Catalyst Request For Proposal by DOJ's SCR Consultant
 - Responses to EPA's Submittals of SCR Catalyst Vendors' Responses to DOJ's SCR Consultant's Request For Proposal
 - Responses to DOJ's SCR Consultant's April 2010 Report
 - Responses to General Comments by DOJ's SCR Consultant
 - SCR Reactors, Gas-Gas Heat Exchangers, and General SCR Equipment Arrangements
 - SCR Catalyst Exchange Frequency
 - Microbeam Technologies report on MRYS Unit 2's measured flue gas particulate emissions
 - Responses on individual comments to NDDH's January 2010 request

¹³ See Reference number 12, November 25, 2009*.

¹⁴ See Reference number 15, January 11, 2010*.

¹⁵ See Reference number 13, December 11, 2009*.

¹⁶ See Reference number 14, December 21, 2009*.

¹⁷ See Reference number 16, February 11, 2010*.

¹⁸ Ibid Reference number 7, October 2006*.

- Responses to EPA's SCR Cost Analysis
- Summary of Responses to EPA and DOJ's SCR Consultant's Comments
- Responses to May 2010 National Park Service Comments
- Responses to January 2010 National Parks Conservation Association Comments
- Conclusions

Responses to May 2010 EPA Comments on NO_x BACT Determination for Milton R. Young Station

EPA's NSR Workshop Manual and OAQPS Control Cost Manual for Calculating SCR Control Cost Effectiveness

We believe that the EPA has incorrectly interpreted the New Source Review (NSR) Workshop Manual (NSR Manual) and improperly compared NO_x control costs of hypothetically-applied low dust and tail end SCRs on cyclone boilers firing North Dakota lignite to other emission sources of dissimilar type, and ignored the other mitigating circumstances that the NDDH considered before issuing their revised preliminary BACT Determination for the M.R. Young Unit 1 and Unit 2 boilers.

On page 2 of the EPA's comments, a quote from the NSR Manual was included: "if the cost of reducing emissions ...as the cost previously borne by *other sources of the same type* [emphasis added] in applying that control alternative...the alternative should be *initially* [emphasis added] considered economically achievable..."¹⁹.

In reference to comparing control costs of hypothetically-applied low dust and tail end SCRs on cyclone boilers firing North Dakota lignite, the EPA's use of examples from other types of NO_x emission sources ignores the NSR Manual's statement included above, with emphasis that the comparison is "to other sources of the same type". As the NDDH has pointed out in its "Selective Catalytic Reduction (SCR) Technical Feasibility for M.R. Young Station" report, the "EPA has recognized in the past, that cyclone boilers, such as those at Minnkota, that burn lignite from North Dakota is a separate source category for NO_x emissions limits under the New Source Performance Standards, Subpart D and Da"²⁰.

The disconnect between the EPA's argument and the NSR Manual appears to be related to the EPA's interpretation that the "determination of BACT is based upon the pollutant that triggered PSD, in this case NO_x, for any type of source can be compared to the cost effectiveness of any other source of NO_x"²¹. This

¹⁹ Ibid Reference number 2, page 2, May 2010*.

²⁰ Ibid Reference number 6, Appendix B.6, page 16.

²¹ Ibid Reference number 2, page 4*.

does not agree with the quote from the NSR Manual that started the EPA's argument. The EPA provides no relevant references to regulatory documents that support their convoluted argument that disagrees with the NSR Manual statement that such comparisons are to be made to "other sources of the same type". It is obvious that Minnkota does not operate a refinery modified to produce low sulfur gasoline, nor other types of units mentioned in the EPA's BACT and permit application references. The word "initially" in the EPA's first quote referenced above also seems to have escaped detection by the EPA in the argument they presented.

We disagree with EPA claims that the NDDH's Draft BACT Determination "relied upon unreasonable assumptions and factors not authorized by law"²² and "did not follow the requirements in these manuals"²³ in reference to the EPA's NSR Manual and OAQPS Control Cost Manual. The NSR Manual states "...procedures for estimating control equipment costs are based upon EPA's OAQPS Control cost Manual and are set forth in Appendix B of this document" [i.e. the NSR Manual]. It continues with "Applicants should closely follow the procedures in the appendix and any deviations should be clearly presented and justified in the documentation of the BACT analysis. Also, "...where initial control cost projections on the part of the applicant appear excessive or unreasonable (in light of recent cost data) more detailed and comprehensive cost data may be necessary to document the applicant's projections". Furthermore, "costs should be site specific"....and "the applicant should document any unusual costing assumptions used in the analysis"²⁴.

Appendix B of the NSR Workshop Manual further states: "If standard costing factors are used, they may need to be adjusted due to site specific conditions". Also, "Indirect installation costs include (*but are not limited to*) [emphasis added] engineering, construction, start-up, performance tests, and *contingency* [emphasis added]. Estimates of these costs may be developed by the applicant for the specific project under evaluation". Furthermore, "These references [includes OAQPS Control Cost Manual] can be used by applicants *if they do not have site-specific estimates prepared...*" [emphasis added]. "Where an applicant uses different procedures or assumptions for estimating control costs than contained in the referenced material or outlines in the document, the nature and reason for the differences are to be documented in the BACT analysis"²⁵.

The costs estimated for the hypothetical low-dust and tail end SCR alternatives evaluated for Minnkota were site-specific, and based upon vendor equipment proposals with relevant materials, labor, and other direct and indirect cost factors. We believe the quoted statements from the NSR Manual indicate that a detailed, site-specific total capital investment cost estimate, such as developed for the Supplemental NO_x BACT Analysis

²² Ibid Reference number 2, page 1 May 2010, *.

²³ Ibid, page 10*.

²⁴ Ibid Reference number 11, page B.35.

²⁵ Ibid, pages b.3 and b.4.

Study for Unit 1 and Unit 2 at MRYS that uses assumptions different than those given in the EPA's OAQPS Control Cost Manual for SCRs, is allowed. Furthermore, the calculations given in the OAQPS Control Cost Manual for SCR as recommended by the NSR Manual to be used in BACT cases of typical hot-side, high dust installations when site-specific details are not available for low-dust or tail-end SCR configurations. In fact, the OAQPS Control Cost Manual specifically indicates those calculations should not be used for low-dust or tail-end SCR configurations including the use of flue gas reheat.

The NDDH's Draft BACT Determination for the M.R. Young Unit 1 and Unit 2 boilers relies upon the original 2006 NO_x BACT Analysis Study and the November 2009 Supplemental NO_x BACT Analysis Study, and numerous Minnkota-provided responses to agency questions and comments. This body of submitted technical information includes documentation of significant assumptions made as part of the control cost estimating approach used in the MRYS NO_x BACT Analysis studies. We believe that the EPA's interpretation of the requirements of the Consent Decree, NSR Manual, and OAQPS Control Cost Manual conflicts with the statements quoted above. The EPA's arguments fail to recognize the procedures and assumptions used to produce the cost estimate information submitted by Minnkota in these cases are not disallowed by the NSR Manual in keeping within the statements quoted herein. Deviations from the prescribed cost estimating procedures and assumptions described in the NSR Manual and OAQPS Control Cost Manual are misstated as "unauthorized by law"²⁶ when the former allows for such departures in such cases as Minnkota's NO_x BACT Analysis studies.

We repeat our argument stated previously²⁷ that the OAQPS Control Cost Manual for SCRs cannot be used in Minnkota's cases for estimating control costs of hypothetical low-dust and tail end SCRs because of the disclaimer it contains: "*The costs for the tail-end arrangement, however, cannot be estimated from this report because they are significantly higher than high-dust systems due to flue gas reheating requirements*"²⁸ [emphasis added]. By similarity, this applies to cold-side low-dust SCRs as well, because of the need for flue gas reheating. The low-dust SCR configuration assumed in the OAQPS Control Cost Manual for SCR was a hot-side arrangement downstream of a hot-side electrostatic precipitator (ESP), which does not require flue gas reheat²⁹. As per the quoted statements from Appendix B of the NSR Manual noted immediately above, preparing and using site-specific cost estimates with documentation of deviations from the prescribed assumptions is, in fact, allowed, and, in Minnkota's case, is more realistic in capturing the probable actual costs that would be incurred from implementing, operating, and maintaining the hypothetically-applied low-

²⁶ Ibid Reference number 2, page 1, May 2010*.

²⁷ Ibid Reference number 13, December 11, 2009, pages 2 and 3*.

²⁸ Ibid Reference number 17, October 2000, page 2-41.

²⁹ Ibid, page 2-20.

dust and tail end SCRs studied than estimates prepared by strictly following the references cited in the EPA's May 2010 comments in violation of the disclaimer stated therein.

Again, we disagree that the EPA's [and NPS's] interpretations of the NSR Manual and OAQPS Control Cost Manual are consistent with the statements quoted above; in fact their interpretations are contrary to them.

The Supplemental NO_x BACT Analysis Study for Unit 1 and Unit 2 at MRYS applied appropriate cost estimating methods following standard engineering practices to avoid the conflicts posed by closely following procedures in the NSR Manual and OAQPS Control Cost Manual which are not in agreement with the qualifying disclaimer statements included above. This capital cost estimating methodology is generally supported by information presented in one of the reference documents (Cichanowicz, 2007)³⁰ in the EPA's May 2010 comments, which gives examples of indirect charges and assumptions to be included as part of a capital cost estimate for power plant emissions control technology implementation.

(by Cichanowicz, copied from Reference number 14, page 18, June 2007)

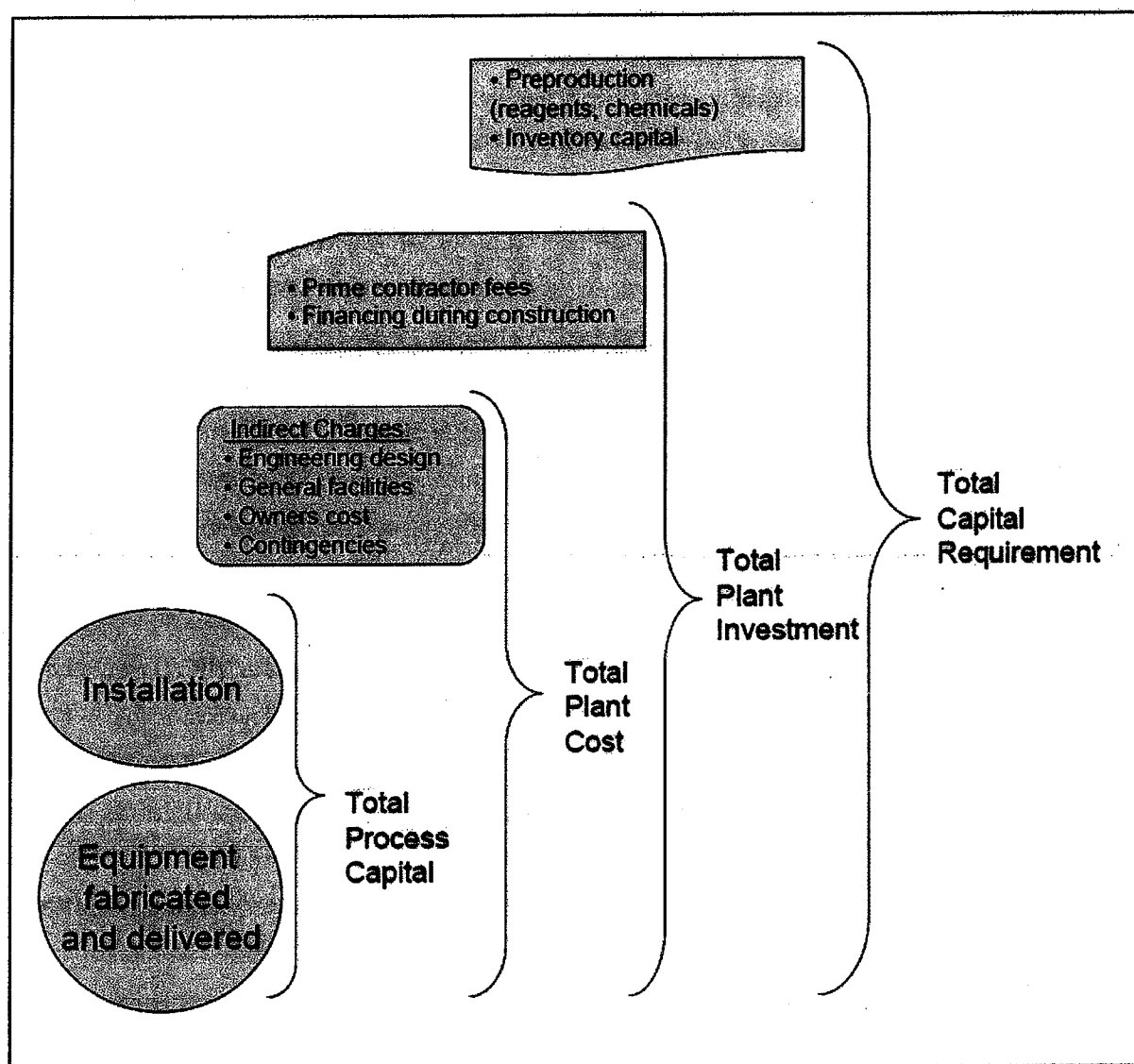
Table 5-1 Examples of Indirect Charges, Assumptions

Cost Element	Purpose	Range, %
Engineering	Establish design	7-15
General Facilities	Roads, buildings, shops, laboratories	2-5, based on process capital
Owner's Cost	Staff, management	5-10
Process Contingency	Uncertainty in process operation	5-10, for a mature process
Project Contingency	Uncertainty in site installation	5-10, if detailed engineering initially completed
Prime Contractor Fees	Business cost	2-8
AFDC	Financing during construction	5-10
Preproduction	Supply of parts, consumables	2, based on total process investment, plus 30 days fixed, variable O&M
Inventory Capital	Supply of consumables	Based on 30 day reagent, chemicals storage

It should be noted that percentages in the table of indirect charges and their assumptions are shown with a range, and the numbers presented are themselves based on various assumptions, such as "for a mature process" for process contingency, and "if detailed engineering initially completed" for project contingency.

³⁰ See Reference number 18, June 2007.

(by Cichanowicz, June 2007 - copied from Reference number 14, page 18, Figure 5.1)



While we do not necessarily agree with the assumed percentages in the Cichanowicz paper as appropriate for Minnkota's non-typical hypothetical applications of low-dust and tail end SCR cases at this stage of project development, this methodology is illustrative of an alternate standard estimating approach. Also included in the indirect costs shown above is "Allowance for Funds During Construction (AFDC)" which the OAQPS Control Cost Manual for SCR assumed as zero³¹ but Cichanowicz listed an assumption of 5-10% of Total Plant Cost (which is shown in Figure 5.1 copied herein). A significant portion of the Cichanowicz paper also discussed the rampant cost escalations incurred by many recent power plant emission control projects, involving both basic construction materials for shop and field-fabricated equipment, and construction labor.

³¹ Ibid Reference number 17, October 2000, page 2-44.

It is unrealistic to believe that low-dust and tail end SCR projects of such significant complexity, scarcity, size, and schedule duration can be accurately estimated based upon design, fabrication, and erection being delivered and completed “overnight” as a BACT analysis assumes, without including adequate allowances for costs which are not fixed and which will be incurred several years into the future. This is especially important when considering the volatility of project materials and labor costs, and the costs of capital funding which Cichanowicz’s paper highlighted. These project execution allowance factors have been estimated by Burns & McDonnell separately from the various contingencies that are recognized in the OAQPS Manual for SCR. We reject the EPA’s argument that the assumed contingencies shown in the OAQPS Control Cost Manual are all encompassing in their coverage, and “should” include sufficient amounts for such things as escalation, and that to include the latter separately is essentially double counting. This interpretation fails to recognize cost and scope risks that equipment suppliers and installation contractors will need to be compensated for if required to provide fixed lump-sum pricing for such a project. To expect the process and project contingencies assumed in the example shown in the OAQPS Control Cost Manual to adequately cover all unforeseen installed capital costs that the EPA’s comments³² describe is unrealistic.

We dispute EPA’s comment that “The differences for the basic capital cost equipment at MRYS would not be expected to differ from other SCR installations on the scale estimated by B&McD and no reasonable explanation has been provided by Minnkota for the large disparity”³³. Each cost estimate and BACT analysis case are based upon numerous conditions and assumptions that are unique to that particular situation. The fact that there was not a tail end SCR that had been designed, built, tested and was operating successfully on a coal-fired utility boiler in the United States when the original NO_x BACT Analysis Study reports for MRYS were submitted in October 2006, and nowhere else in the world with such challenging fuel and flue gas constituents as present at MRYS, seems to have been disregarded by the EPA’s commenter. Likewise, there were few low-dust SCRs with reheat installed that were operating in the U.S. on coal-fired utility boilers in 2006. There is a distinct lack of comprehensive design, operating, and maintenance technical and cost details in publicly-available documents pertinent to each case.

The EPA’s claimed disparity between their expectation of estimated capital costs and the numbers provided in the November 2009 Supplemental NO_x BACT Analysis Studies for MRYS Unit 1 and Unit 2, with additional information included in subsequent responses to the NDDH, appears prejudicial on the EPA’s part and does not recognize that significant efforts have been expended to produce and document these results. The fact that the estimated site-specific total installed capital costs of the hypothetical applications of SCRs in Minnkota’s Supplemental NO_x BACT Analysis studies do not correspond with EPA’s expectations is not a

³² Ibid Reference number 2, page 13, May 2010*.

³³ Ibid, page 13, May 2010*.

result of Burns & McDonnell improperly accounting for design, procurement, and installation conditions. We believe it is a failure on the EPA's part to recognize the limitations of their own assumptions with respect to use of the OAQPS Control Cost Manual, which does not accurately estimate costs of these technologies as it includes the previously-stated caveat not to use the referenced report for such cases because of its inadequacies.

Of particular difficulty in comparing installed capital and operating/maintenance cost estimates for such NO_x control systems are the scope and factors involving plant equipment and site impacts requiring "balance of plant" modifications. We reject the EPA's statement that "many of the assumptions and design parameters that B&McD specified to SCR system and catalysts vendors resulted in excessive equipment components and sizing of the SCR system and the auxiliary/balance of plant components, which drove up materials and labor costs. If the system was designed to minimize capital costs, the general design would be different and the cost of materials and labor would be much less"³⁴.

Burns & McDonnell and Minnkota carefully considered many engineering, design, procurement, installation, operation and maintenance challenges involving hypothetical applications of low-dust and tail end SCRs at MRYS, and determined what could be required to avoid or compensate for such impacts. The approach of the SCR cost estimate effort performed by Burns & McDonnell for Minnkota was to develop scope and conceptual designs, involve knowledgeable vendors and equipment suppliers for technical information and pricing, and quantify equipment, procurement, installation, operation, and maintenance requirements while recognizing the substantial technical risks that the site and flue gas conditions imposed. The objective was not to minimize capital cost, for that is not a worthwhile pursuit if it is likely to result in failure of the project to be constructable, operable, reliable, maintainable, or meet performance requirements over the expected life of the equipment. As there are no assurances that low-dust and tail end SCRs will even meet all or some of the objective criteria noted above, it is purely speculative that the EPA or their consultant have provided estimates that minimize costs and technical risks while meeting and maintaining emissions performance for the life of the SCRs being considered for Milton R Young Station more comprehensively than what Minnkota has provided.

We reject the EPA's claim that "the B&McD analysis that the NDDH relied upon included redundant costs", where an example given was the SCR bypass ducts and isolation dampers³⁵. The SCR system supplier that provided the indicative pricing for the major SCR system equipment has confirmed (verbally) that their June

³⁴ Ibid, page 13, May 2010*.

³⁵ Ibid, page 14, May 2010*.

1, 2009 proposal³⁶ misstated their scope involving the SCR flue gas bypass ductwork for maintenance – it was not included in their scope and pricing, nor were any SCR reactor isolation dampers. These items were included as part of Burns & McDonnell's cost estimate that was described in the November 2009 Supplemental NO_x BACT Analysis Studies for MRYS Unit 1 and Unit 2, with additional information included in subsequent responses to the NDDH³⁷.

Minnkota's Consent Decree requires that a BACT analysis for NO_x emissions from MRYS be performed, which has been done. It should be noted that other impact factors, including incremental control costs, must be considered before the BACT alternative are established, which was done by NDDH.

³⁶ Telephone conference call between Burns & McDonnell and Babcock Power on October 9, 2009. This document was submitted to the NDDH and claimed as confidential in accordance with Air Pollution Control Rules for the State of North Dakota at 33-15-01-16. See Reference number 16, page 2, for additional details.

³⁷ Ibid Reference number 9, November 12, 2009*; Reference number 13, December 11, 2009*; Reference number 14, December 21, 2009*; and Reference number 16, February 2010*.

Responses to EPA Comments on SCR Annual Cost Estimates and Methods

We disagree with the EPA's statement that "B&McD also used inflated and unjustified cost estimates for annual costs and used costing methods that are unauthorized by the Control Cost Manual"³⁸. Our responses to several of the EPAs' comments are as follows:

1. We repeat our argument stated previously that the OAQPS Control Cost Manual for SCRs cannot be used in Minnkota's cases of hypothetical low-dust and tail end SCRs because of the disclaimer it contains. The OAQPS Control Cost Manual for SCR assumes that "the SCR system incorporates only a few pieces of rotating equipment (e.g. pumps, motors, etc.)". Also, "annual maintenance labor and material cost in dollars per year (\$/yr), including nozzle tip replacement for injectors, is *assumed* [emphasis added] to be 1.5% of the Total Capital Investment (TCI) in dollars"³⁹. Appendix B of the NSR Manual states "Maintenance costs in some cases are estimated as a percentage of total capital investment. Maintenance costs include actual costs to repair equipment and *also other costs potentially incurred due to any increased system downtime which occurs as a result of pollution control system maintenance*" [emphasis added]⁴⁰.

Burns & McDonnell assumed 3% of the estimated total capital investment for annual maintenance costs due to anticipated and potential difficulties in maintaining the low-dust and tail end SCR-related equipment that is not part of the conventional hot-side high dust SCR installations to which the OAQPS Control Cost Manual for SCRs applies. Examples of such equipment include: rotary regenerative gas-gas heat exchangers (GGHs), which are the largest pieces of rotating equipment in the entire power plant; booster fans; urea-to-ammonia conversion equipment, which include burners and fans; isolation dampers, and related balance of plant equipment, including rotating equipment that is required for on-line cleaning of catalyst and GGH elements.

The high emissions reductions required for sulfur dioxide at MRYS per the Consent Decree will not allow significant flue gas leakage across the GGHs and still achieve low SO₂ stack emissions. Rotary regenerative GGHs are prone to such leakage problems, element fouling from ammonia and sulfur-related compounds, and corrosion. The harsh winter climate in North Dakota (below -40°F) and nearly constant high winds year-round are significant considerations for equipment located outside and adjacent to the plant's outdoor active coal storage area.

³⁸ Ibid Reference number 2, page 17, May 2010*.

³⁹ Ibid Reference number 17, page 2-45, October 2000.

⁴⁰ Ibid Reference number 11, page b.8, October 1990.

We believe the EPA's assumption of 1.5% of the estimated total capital investment for annual maintenance costs is insufficient to adequately represent the costs needed to maintain the low-dust and tail end SCR-related equipment described above.

2. We disagree with the EPA's comment⁴¹ that anhydrous ammonia is mandated as the only reagent to be used for NO_x control in Minnkota's cases of hypothetical low-dust and tail end SCRs. A gaseous, diluted ammonia mixture is required for injection into the SCR reactor to effect the reduction of nitrogen oxides in the presence of catalyst. The OAQPS Control Cost Manual for SCR simply assumes that "the annual cost of ammonia purchase in \$/yr is estimated...."⁴². We point out that the DOJ's SCR consultant's Request for Proposal (RFP) included "SCR grade aqueous ammonia is intended to be used as a reagent"⁴³. Apparently he also disagrees with the EPA's dictate for the use of anhydrous ammonia. Urea-to-ammonia conversions systems have been installed on several conventional hot-side, high dust SCRs at coal-fired utility power plants in the United States, so this equipment appears to be proven in similar circumstances. We see no evidence presented by the EPA that the least expensive reagent that has been previously used elsewhere and is assumed to be available at MRYS (which has not been confirmed with any suppliers) must be selected regardless of issues of public health and safety, or that this must override the other plausible reasons for the selection of urea as the reagent of choice.

3. The number of additional outage hours estimated for Minnkota's cases of hypothetical low-dust and tail end SCRs in the November 2009 Supplemental NO_x BACT Analysis studies is not solely a matter of catalyst replacement duration and frequency. Other reasons for additional outage hours include considerations such as: frequent forced boiler outages due to boiler tube leaks that may cause severe fouling of the low-dust SCR catalyst, low-dust SCR GGHs or tail end FGD GGHs with flyash deposits rich in sticky sodium, calcium, sulfur-containing phases. The formation of these deposits would extend boiler outages to allow adequate removal of the deposits from the SCR equipment exposed to flue gas. In addition, other forced outages of SCR-related equipment such as booster fans, GGHs, and balance of plant equipment can occur. These components must be taken out of service for repairs, causing forced unit outages or load curtailments. We believe it is unrealistic to not include allowances for such potential problems that may occur or be aggravated by the nature of the equipment, fuel, flue gas, weather, and other plant operations when it comes to additional outage hours estimated for Minnkota's cases of hypothetical applications of low-dust and tail end SCRs.

⁴¹ Ibid Reference number 2, page 17, May 2010*.

⁴² Ibid Reference number 17, page 2-46, October 2000.

⁴³ Ibid Reference number 2, Enclosure 15, February 2010*.

Additional boiler outage hours for MRYS NO_x BACT Analysis alternatives involving advanced separated overfire air (ASOFA) were estimated prospectively, i.e., based upon forecasting possible outcomes prior to installation and operation with actual available historical data. A Unit availability reduction of 2.2% (188 hours per year for M.R. Young Station Unit 1, 181 hours per year for M.R. Young Station Unit 2), was assumed, which allowed for forced or extended scheduled boiler outages that could result from problematic cyclone slag tapping, excessive heat transfer surface fouling, increases in boiler tube leaks and other problems related to the operation of air-staged cyclone combustion. Estimates of additional boiler outage hours for alternatives with technologies in combination with ASOFA were assumed to be additive, not overlapping. For MRYS NO_x BACT Analysis alternatives, such forced or extended scheduled boiler outages were assumed to not occur concurrently. This approach was consistently applied for SNCR with ASOFA, various forms of reburn with ASOFA, and hypothetical cases of SCR with ASOFA.

4. We disagree with the EPA's comments⁴⁴ that the NSR Manual does not allow the use of a levelizing cost approach for estimating annual control costs of alternatives in a BACT analysis. Under "Total Annual Costs" in Appendix B Estimating Control Costs of the EPA's NSR Manual, the first sentence states "The permit applicant should use the *levelized* [emphasis added] annual cost approach for consistency in BACT cost analysis"⁴⁵. The original 2006 NO_x BACT Analysis Study of Minnkota's Unit 1 and Square Butte Electric Cooperative's Unit 2 at the Milton R. Young Station, and the November 2009 Supplemental NO_x BACT Analysis Study used a levelized annual cost method consistently for all alternatives analyzed for control cost effectiveness. It would not provide consistency between the MRYS 2006 and 2009 NO_x BACT Analysis studies to disallow the use of an annual cost levelizing factor only for the cases of hypothetical SCR application at MRYS. We believe it is especially relevant to use a levelizing cost factor due to different scenarios for catalyst replacement, boiler cleaning and major scheduled unit outages that affect annual operating hours assumed in the BACT analyses.

5. We reject the EPA's comment that Minnkota must justify reasons why regenerated replacement catalyst was not considered⁴⁶. It is unproven that catalyst can be adequately restored after exposure to the flue gas emitted from cyclone boilers firing North Dakota lignite. Further, it is unreasonable that the use of such significant and unproven assumptions must be used in MRYS NO_x BACT Analysis alternatives involving hypothetical applications of low-dust and tail end SCR technologies. We see no evidence presented by the EPA or their consultant that regenerated catalyst was assumed in any of the other cost effectiveness analyses referenced in the EPA's comments.

⁴⁴ Ibid, Reference number 2, page 22, May 2010*.

⁴⁵ Ibid Reference number 10, Appendix B, page b.4.

⁴⁶ Ibid Reference number 2, page 22, May 2010*.

6. We disagree that the Scenario B assumptions for possible catalyst life used in the Supplemental MRYS NO_x BACT Analysis alternatives involving hypothetical applications of low-dust and tail end SCR technologies are “unsubstantiated and arbitrary”⁴⁷. Minnkota has previously provided proposals from catalyst vendors that refused to offer guarantees for catalyst life when these vendors have been given details of the measured MRYS flue gas contaminants including sodium-rich aerosols⁴⁸. Comparisons between MRYS coal ash-forming constituents and flue gas characteristics, including amounts and size distribution of sodium-rich aerosols emitted versus other available published technical literature including data from bench, pilot, and full-scale catalysts tested for deactivation have been provided in previous responses and BACT Analysis Study reports by Minnkota. Because there have been no demonstrations of SCR catalyst exposed to flue gas emitted from any cyclone boilers firing North Dakota lignite that showed the ability to withstand the conditions without severe plugging and fouling, it is unproven that low-dust and tail end SCR technologies will even succeed in such applications. It is unreasonable for the EPA and their consultants to ignore this information as the basis of estimates for possible catalyst lifespans assumed in the 2009 Supplemental NO_x BACT Analysis studies for MRYS Unit 1 and Unit 2. This is further discussed in responses to SCR catalyst Request For Proposal and the DOJ’s SCR consultant in the sections that follow.

Furthermore, the identification of Scenario B, in which it is assumed that one layer of catalyst must be changed out at each scheduled boiler cleaning outage, is not arbitrary, but instead represents the minimum catalyst life that could be reasonably accommodated at M.R. Young Station. In light of the catalyst vendors’ refusal to guarantee catalyst life until a pilot scale test has been successfully completed, Scenario B brackets (at the low end) the minimum catalyst life that could be considered. It should be noted that the NDDH has established its own criteria for minimum acceptable catalyst life at 10,000 hours of operation.

Responses to EPA Comments on SCR Catalyst Request For Proposal by DOJ’s SCR Consultant

Reference was made in the EPA’s comments⁴⁹ to a “Request For Proposal for Conceptual SCR Catalyst Design for a Low-Dust and Tail-End SCR System”⁵⁰ dated February 2010 by the DOJ’s SCR consultant, which was included in Enclosure 15 of the EPA’s May 2010 comments. The referenced RFP was “intended to generate conceptual design and SCR performance guaranty information for the retrofit of either a cold-side low-dust or a tail-end SCR system on two different coal-fired electric generating units”⁵¹. This RFP also

⁴⁷ Ibid Reference number 2, page 26, May 2010*.

⁴⁸ Ibid Reference 16, February 2010* as part of Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 160-219, February 2010*.

⁴⁹ Ibid Reference number 2, page 13, May 2010*.

⁵⁰ Ibid, Enclosure 15, page 3, February 2010*.

⁵¹ Ibid page 3, February 2010*.

specified that “The unit is intended to have a single SCR DeNO_x reactor...either in a cold-side low-dust configuration downstream of the air heater and electrostatic precipitator and upstream of a wet limestone forced oxidation FGD scrubber or downstream of the wet forced oxidation FGD scrubber and before the stack. A rotary regenerative gas-gas heater (RGGH) followed by either a natural gas-fired duct burner or a high temperature steam coil ensures the necessary flue gas temperature for the SCR process of 290 °C (554 F)”⁵². The two units were not identified as belonging to Minnkota and Square Butte in the RFP, which the EPA described as “[w]hile the facility in the RFP was not identified as MRYS, the flue gas characteristics in the RFP were based on relevant actual flue gas parameters found at MRYS, including recent stack test information for Unit 1 and Unit 2 and the 1983 Markowski data on particulate matter concentrations and compositions data for Unit 2. Furthermore, it was clearly stated in the RFP that the majority of the sulfates within the particulate matter are expected to be sodium and potassium sulfates”⁵³. There were numerous omissions, inaccuracies, and system details related to the referenced Evonik RFP that should be noted:

1. Minnkota’s existing wet flue gas desulfurization system on Unit 2 currently uses natural oxidation chemistry with lime (and flyash until December 31, 2010) reagent, not forced oxidation using limestone⁵⁴ as a reagent. Use of lime instead of limestone will cause a difference in the amount of reagent consumption and carbon dioxide released (from the limestone reacting with sulfur). The RFP was inaccurate in describing the wet flue gas desulfurization systems, which could alter the catalyst suppliers understanding of flue gas conditions and constituents.
2. Natural gas-fired duct burner or high temperature steam coil was mentioned as the source of heat addition to achieve final reactor flue gas temperature. This departs from EPA’s comments⁵⁵ (which we have rejected) that only steam should be assumed as the source of flue gas reheat addition in the MRYS NO_x BACT Analysis study cases involving hypothetical applications of SCR technology.
3. On-line catalyst cleaning was not required unless otherwise requested by the catalyst supplier⁵⁶. With no successful SCR experience with North Dakota lignite fired boiler applications, and significant fouling and plugging demonstrated in the Coyote pilot-scale SCR slipstream testing, the catalyst suppliers may look at biomass-fired boiler experience for determining needs for on-line catalyst cleaning. It should be noted that biomass-fired boilers typically have lower sulfur emissions than coal-fired boilers, so the reaction of sulfur

⁵² Ibid, page 3, February 2010*.

⁵³ Ibid Reference number 2, page 23, May 2010*.

⁵⁴ Ibid Reference number 2, Enclosure 15, page 3, February 2010*.

⁵⁵ Ibid, page 22, May 2010.

⁵⁶ Ibid Reference number 2, Enclosure 15, page 3, February 2010*.

oxides in combination with sodium and potassium may not be a significant fouling issue for biomass-fired boilers compared to what is prevalent with North Dakota lignite fired boiler applications.

4. SCR grade aqueous ammonia was specified as the intended reagent⁵⁷. This departs from EPA's recent comments that only anhydrous ammonia should be assumed as the reagent in the MRYS NO_x BACT Analysis study cases involving hypothetical applications of SCR technology. See our comments herein which reject the EPA's assumption regarding anhydrous ammonia.

5. SCR reactor flue gas bypass was not required unless otherwise requested by the catalyst supplier⁵⁸. This approach appears to allow a catalyst supplier unfamiliar with Minnkota's boiler fireside cleaning practices (not described in the RFP) to ignore the expected contamination and poisoning of catalyst from passage of moisture and entrained ash liberated from heat transfer surfaces during frequent boiler cleaning outages. It also fails to protect the catalyst from moisture condensation that will mobilize the soluble sodium and potassium salts during frequent and possible prolonged startup periods when temperatures can be below dewpoint. The mobilized sodium and potassium will cause poisoning of catalyst sites. With no successful pilot- or full-scale SCR experience with North Dakota lignite fired boiler applications, it is a curious approach to leave it up to the catalyst suppliers to determine whether SCR flue gas bypass is needed on North Dakota lignite fired boiler applications. We believe that SCR reactor flue gas isolation dampers (and catalyst warming systems for boiler outages) would be necessary if such technology were applied to MRYS boilers.

6. Flue gas, flyash, and reagent compositions were specified⁵⁹, but coal analyses were not included in the original RFP issued by the DOJ's SCR consultant. We believe this purposely hides the true character of the fuel burned from the catalyst suppliers, so that they may not fully understand the importance of fuel associated impurities on the formation of gas phase species from flame vaporized sodium and potassium that condense to produce aerosols during gas cooling as well as the importance of the non-volatile impurity fraction on the fly ash characteristics in the flue gas stream. This omission of fuel property and composition data from the RFP appears to be intentional so as to obscure the nature of the challenges presented by catalyst exposure to flue gases created from North Dakota lignite burned in cyclone-fired boilers. This omission would tend to result in budgetary designs which undersize initial catalyst volumes, underestimate ammonia slip or overestimate catalyst lifespans. Furthermore, catalyst vendors not provided with site-specific data would be inclined to offer initial catalyst replacement warranties because of this obvious lack of detailed coal and ash analysis and flue gas constituent information.

⁵⁷ Ibid page 3 and page 8, February 2010*.

⁵⁸ Ibid page 3, February 2010*.

⁵⁹ Ibid pages 4-8, February 2010*.

8. The RFP issued by the DOJ's SCR consultant significantly underestimates the number of forced and scheduled boiler outages (by a factor of three to four times)⁶⁰. Maintenance practices such as routine boiler fireside cleaning outages to remove severe accumulations of ash and slag deposits that are characteristic of firing North Dakota lignite were not mentioned. This lack of boiler outage data in the RFP appears to be intentional so as to obscure the nature of the challenges presented by catalyst exposure to fluctuating temperatures of flue gases created from North Dakota lignite burned in cyclone-fired boilers. This omission would tend to result in budgetary designs which undersize catalyst volumes or overestimate catalyst lifespans due to possible lack of perceived need for reactor flue gas bypasses or catalyst on-line cleaning equipment.

9. Possible need for, or inclusion of, reactor warming systems for catalyst protection during outages were not disclosed or mentioned. We believe that SCR reactor catalyst warming systems (and flue gas isolation dampers) would be necessary if such technology were applied to MRYS boilers because of the potential to mobilize soluble sodium or potassium accumulated on the catalyst.

10. The RFP also specified that each boiler should have only a single reactor, and stated that "The module arrangement within the SCR reactor will be determined as close to square as permissible by the proposed number of catalyst modules". The RFP also included "The type, configuration and chemical composition of the catalyst shall be selected based on the catalyst supplier's sole discretion"⁶¹.

It is important to note that the size of any SCR reactor is dependent upon not only the arrangement of the catalyst modules within the reactor but the number of reactors needed to provide the desired flue gas space velocity and satisfy layout and size limitations involving the flue gas inlet and outlet ductwork and gas-gas heat exchanger(s). It is curious that the referenced RFP specified many design factors involving the maximum module size, and minimum catalyst element height dimensions as part of the "... module design shall comply at least with the following minimum design criteria, requirements and/or limitations"⁶² but failed to recognize or mention the maximum allowable size of the reactor because of GGH size limitations. This is discussed further in a subsequent section of these responses.

While the DOJ's SCR consultant's RFP was more specific in certain aspects of reactor design and catalyst configuration than the performance-based information given to the vendors by Burns & McDonnell and Minnkota with Steve Benson of the University of North Dakota in 2009, there are other key differences. The previous effort involving Minnkota provided a design basis to the catalyst vendors including a very detailed characterization of the coal and ash composition, along with particulate components in the flue gas stream

⁶⁰ Ibid page 4, February 2010*.

⁶¹ Ibid page 8, February 2010*.

⁶² Ibid page 8; February 2010*.

with actual aerosol data for the flue gas desulfurization system absorbers' inlets and outlets, and at the inlet to Unit 2's electrostatic precipitator, based on values measured in 2009. This flue gas characterization was different than the one provided by the DOJ's SCR consultant. Sodium and potassium were only mentioned once in the DOJ's SCR consultant's RFP when discussing sulfate particulates in the flue gas streams. Mass loadings of sulfate compounds in the RFP appear to be lower than actual detailed analysis has demonstrated⁶³. It appears that the DOJ's SCR consultant used the lower levels of particulate measured by Markowski.

Apparently, the scope of the referenced RFP was subsequently altered, presumably by the DOJ's SCR consultant, for at least one of the catalyst vendors. This RFP modification added a "high pressure drop" option that incorporates smaller catalyst flue gas path opening spacing (pitch) compared to the base design. This alteration is believed to have been done via email correspondence between March 4th and March 24th; it was not documented in the original RFP dated February 2010 which was issued on March 3, 2010 or in the non-confidential business information documents submitted to the NDDH with the RFP by the EPA.

Responses to EPA's Submittals of SCR Catalyst Vendor's Responses to DOJ's SCR Consultant's Request For Proposal

It is difficult to understand how the catalyst suppliers, when requested to respond to the subject RFP, can provide proposals that include complete and realistic design information and guarantees for catalyst lifetime when they are not advised of certain design, operating and maintenance conditions, some of which are not commonly seen in typical coal-fired boiler SCR applications. Proposals in response to the DOJ's SCR consultant's Request For Proposal (Evonik RFP) were submitted by three catalyst vendors (CERAM, Johnson Matthey Catalysts (JMC), and Haldor Topsoe). According to the EPA in their May 2010 comments "[u]pon request from two catalyst vendors (CERAM and JMC), a typical coal composition of Center lignite was provided"⁶⁴. These catalyst proposals were subsequently submitted to the NDDH as "confidential business information" by the EPA separately from the EPA's May 2010 comments⁶⁵.

Two of these proposals were by the same vendors (CERAM and Haldor Topsoe) that Burns & McDonnell, Minnkota, and Steve Benson of the University of North Dakota, had engaged to provide preliminary catalyst conceptual design and pricing information in 2009 for hypothetical LD and TESCR applications at MRYS. These two vendors were not instructed to consider the very detailed site-specific boiler information, the actual coal and ash analyses, or the 2009 flue gas aerosol data (all of which are part of the public record on the NDDH's website) for characterizing the fuel and flue gas composition upstream of the Unit 2's electrostatic

⁶³ Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 279-280, February 2010*

⁶⁴ Ibid Reference 2, page 23, May 2010.

⁶⁵ See Reference number 19, June 2010*.

precipitator, flue gas desulfurization system absorber inlet and outlet provided previously by Minnkota and their consultants. The intentional omission of fuel and ash composition data from the Evonik RFP as initially issued obscured the nature of the challenges presented by catalyst exposure to flues gases created from North Dakota lignite burned in cyclone-fired boilers, and caused at least one of the catalyst vendors (Haldor Topsoe) to misunderstand the fuel burned in the requested applications. This misunderstanding will be elaborated on later in this document.

The prices requested from catalyst vendors by the DOJ consultant's RFP are current in 2010 dollars for procurement only. This is not consistent with the premise that the hypothetical SCR cases in the November 2009 Supplemental NOx BACT Analysis studies for MRYS Unit 1 and Unit 2 were based on the use of catalyst replacement costs estimated for 2006. Catalyst purchase prices requested from vendors do not include all costs involved in planning and executing the replacement activities, including storage, installation and removal labor, handling and transportation equipment charges, mobilization and demobilization, profit, or disposal costs.

CERAM

CERAM provided budgetary catalyst designs and pricing, dated March 31, 2010, in response to the referenced Evonik RFP and subsequent RFP alterations. CERAM offered catalyst performance guarantees including NOx removal efficiency, maximum ammonia slip, initial pressure drop, sulfur dioxide (SO₂) to sulfur trioxide (SO₃) conversion rate, initial and subsequent catalyst lifetimes with pricing, expected exchange cycle diagram (not guaranteed), and "fill-in technical data" for the base and optional high pressure drop catalyst cases for a low-dust SCR on Unit A (representing MRYS Unit 1) and a tail end SCR on Unit B (representing MRYS Unit 2)⁶⁶.

Although the EPA claims that CERAM was one of the catalyst vendors that was subsequently provided with "a typical coal composition of Center lignite"⁶⁷, the EPA did not produce any emails from Hans Hartenstein or any telephone call records documenting the submittal of RFP information supplied, nor any written and/or verbal instructions given to CERAM regarding the initial Evonik RFP or the subsequent optional high pressure drop catalyst cases.

On April 8, 2010, CERAM contacted Minnkota by telephone to advise them of the Evonik RFP for unnamed but similar sized coal-fired units as Units 1 and 2 at Young Station. CERAM has subsequently issued a

⁶⁶ Ibid Reference number 19 a., March 2010*.

⁶⁷ Ibid Reference number 2, page 23, May 2010.

letter⁶⁸ to Minnkota explaining their offer of initial ("Test A") and end of life ("Test B") catalyst guarantees for NOx reduction, ammonia slip, SO₂ to SO₃ conversion rate, and pressure drop as part of its proposal in response to the Evonik RFP. This was in contrast to the SCR catalyst proposal that CERAM submitted to Minnkota on October 13, 2009 in which they only provided initial Test A performance guarantees. CERAM believes that additional field testing information, including a pilot test program that would involve flue gas exposure of one to several catalyst elements under conditions that would replicate the actual SCR system for several thousand hours, would be required before they would be able to provide any life guarantees for SCR catalyst at MRYS.

In their June 11th letter to Minnkota, CERAM explained that "although the requests from Evonik and Minnkota were similar, there were distinct differences in the RFP documents"⁶⁹. The key differences were⁷⁰:

- The range of fuel analysis provided by Evonik was not as detailed as that provided by Minnkota, and considered a lower maximum range of key constituents that can contribute to catalyst poisoning. For example the Evonik specification listed the maximum sodium content to be significantly less than the Minnkota specification. Sodium is a significant catalyst poison that must be considered for the purpose of guarantees. CERAM must consider the full range of potential coals when supplying catalyst performance guarantees.
- Minnkota submitted with the RFP the entire study performed by Microbeam Technologies, Inc (MTI) titled *Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD*. This study included detailed flue gas characterization including details on particle size distribution, particle concentrations, and soluble sodium constituents in the flue gas.
- Minnkota submitted with the RFP the final report titled *Impact of Lignite Properties on Powerspan's NOx Oxidation System*. The report outlined the impacts of the North Dakota Lignite flue gas and fly ash on Powerspan's multi-pollutant control system called electrocatalytic oxidation (ECO) technology, specifically the sodium-rich aerosols and small ash particles which accumulated and became bonded to the surface of the silica electrodes used in this technology.

Further, "CERAM would not have included end of life (Test B) performance guarantees in their budgetary proposal to Evonik had their RFP included the same level of detail that was provided in the [2009] Minnkota RFP documents, but would have again recommended a catalyst pilot test program to characterize the impacts of firing North Dakota Lignite coal upstream of SCR catalyst"⁷¹.

⁶⁸ See Reference number 20, June 2010*.

⁶⁹ Ibid, page 1, June 2010*.

⁷⁰ Ibid pages 1 and 2, June 2010*.

⁷¹ Ibid, page 2, June 2010*.

These comments from CERAM confirm the importance of accurately and completely characterizing fuel, ash, flue gas, and particulate streams in order to properly assess the design requirements and offer performance guarantees for SCR catalyst. We believe the Evonik RFP and CERAM catalyst proposal in response to said RFP do not properly describe the situation nor accurately represent the volume of catalyst required for the hypothetical application of low-dust SCR on MRYS Unit 1 and tail end SCR on MRYS Unit 2. We recommend that the NDDH ignore the CERAM proposal in response to Evonik's RFP, based on the above discussion.

Haldor Topsoe

Haldor Topsoe, Inc. (HTI) provided budgetary catalyst designs and pricing, dated March 20, 2010⁷², in response to the referenced Evonik RFP. HTI offered catalyst performance guarantees including NOx removal efficiency, ammonia slip, initial pressure drop, sulfur dioxide (SO₂) to sulfur trioxide (SO₃) conversion rate, initial catalyst lifetimes and expected exchange cycle diagram (not guaranteed), and pricing with "fill-in technical data" for the 90% and 93% catalyst cases of NOx removal efficiencies for a low-dust SCR on Unit A (supposedly representing MRYS Unit 1⁷³) and a tail end SCR on Unit B (representing MRYS Unit 2). The EPA did not produce any emails from Hans Hartenstein or any telephone call records documenting the submittal of RFP information supplied, nor any written and/or verbal instructions given to Haldor Topsoe regarding the Evonik RFP.

Followup by Burns & McDonnell with HTI in June 2010 regarding their proposal to Evonik revealed that it was based on HTI's assumption that the unnamed units in the original Evonik RFP issued by the DOJ's SCR consultant were firing eastern bituminous coal, not North Dakota lignite⁷⁴. We believe this confusion was the direct result of the Evonik RFP lacking any description, coal and ash analysis data or sufficient operating data that identified this application as pertaining to North Dakota lignite-fired boilers. Thus, the catalyst formulation that HTI proposed, which impacts catalyst volumes, pricing, and lifespan estimates, was not selected for specific compatibility with, and recognition of, the nature of the challenges presented by catalyst exposure to flues gases created from North Dakota lignite burned in cyclone-fired boilers. It follows that the proposal and guarantees offered by Haldor Topsoe to the Evonik RFP are inaccurate and invalid relative to the subject boilers at Milton R. Young Station. We recommend that the NDDH ignore the HTI proposal in response to Evonik's RFP, based on the above discussion.

⁷² See Reference number 19 b., March 2010*.

⁷³ Ibid Reference number 2, page 23, May 2010.

⁷⁴ See Reference number 21, July 2010*.

Johnson Mathey

Johnson Mathey Catalysts LLC. (JMC) provided budgetary catalyst designs and pricing, dated March 12, 2010, in response to the referenced DOJ's SCR consultant's Request for Proposal. JMC offered catalyst performance guarantees including NO_x removal efficiency, ammonia slip, initial pressure drop, sulfur dioxide (SO₂) to sulfur trioxide (SO₃) conversion rate, initial catalyst lifetimes and expected exchange cycle diagram (not identified as part of the initial lifetime guarantee), and pricing with "fill-in technical data" for only the 90% catalyst cases of NO_x removal efficiencies for a low-dust SCR on Unit A (representing MRYS Unit 1) and a tail end SCR on Unit B (representing MRYS Unit 2)⁷⁵.

Although the EPA claims that JMC was one of the catalyst vendors that was subsequently provided with "a typical coal composition of Center lignite", the EPA did not produce any emails from Hans Hartenstein or any telephone call records documenting the submittal of RFP information supplied, nor any written and/or verbal instructions given to Johnson Mathey regarding the Evonik RFP. There was no text write-up included with JMC's quote or proposal, no inclusion or mention of any coal analysis requested, received, or reviewed, nor was there any written confirmation provided in the JMC proposal that the catalyst vendor recognized that these unnamed units burn North Dakota lignite. Without inclusion of any identification or discussion about the specific applications in JMC's proposal in response to Evonik's RFP, it is unknown how this vendor considered compatibility with, and recognition of, the nature of the challenges presented by catalyst exposure to flue gases created from North Dakota lignite burned in cyclone-fired boilers at MRYS. We recommend that the NDDH view the JMC proposal in response to Evonik's RFP with skepticism, based on the above discussion.

Responses to DOJ's SCR Consultant's Report

We believe the arguments and comments presented in a April 2010 report⁷⁶ submitted by the EPA from the DOJ's SCR consultant regarding the NDDH's April 10, 2010 BACT Determination for Minnkota's M.R. Young Station contain significant statements that are incorrect, incomplete, speculative and misleading. We offer responses that supplement the detailed information previously provided, and not repeated in their entirety here, that relate to the design basis for the costs determination presented by Burns & McDonnell (B&McD) for the hypothetical application of retrofits of low-dust selective catalytic reduction systems (LDSCR) or tail-end selective catalytic reduction systems (TESCR) to control NO_x emissions for MRYS. The following comments address pertinent major issues rather than a point-by-point rebuttal of Mr. Hartenstein's April 2010 report. These include:

⁷⁵ See Reference number 19 c., March 2010*.

⁷⁶ See Reference number 22, April 2010*.

- Responses to General Comments by DOJ's SCR Consultant
- SCR Reactors, Gas-Gas Heat Exchangers, and General Equipment Arrangements
- SCR Catalyst Exchange Frequency
- Microbeam Technologies Report on MRYS Unit 2's Measured Flue Gas Particulate Emissions
- Responses on individual comments to NDDH's January 2010 request⁷⁷

Responses to General Comments by DOJ's SCR Consultant

SCR Reactors, Gas-Gas Heat Exchangers, and General SCR Equipment Arrangements

We disagree with Hans Hartenstein's negative portrayal of the SCR reactor and gas-gas heat exchanger equipment and ductwork arrangement developed for the conceptual design and cost estimate for hypothetical applications of LDSCR and TESCO technologies at MRYS as "the most costly and unnecessarily complex possible design one could have designed"⁷⁸. The April 2010 "expert" report by Mr. Hartenstein ignores the significant retrofit challenges posed by the site topography with existing and new major air pollution control equipment under construction that are placed in close proximity to active flyash storage silos, scrubber buildings, coal storage areas and coal handling conveyors, plant roadways, and other buildings and structures in the immediate vicinity where low-dust and tail end SCRs and their related ancillary equipment could be located.

Two main SCR reactors, with associated flue gas reheating equipment, ductwork, and ancillary equipment developed for hypothetical LD and TESCO applications at MRYS, were included in the conceptual design and total installed capital cost estimate used in the November 2009 Supplemental NOx BACT Analysis Study report for MRYS Unit 2⁷⁹. A single SCR reactor/GGH "tower" equipment arrangement was developed by the same SCR system supplier (Babcock Power Environmental) who is performing the South Oak Creek LDSCR reactor design and associated equipment arrangement. The technical reasons for this selection are explained below.

The significant reason [not mentioned or acknowledged by the DOJ's SCR consultant] for not having a single LD or TESCO reactor to handle the total flue gas flow from Unit 2's boiler is the size limitation of the rotary regenerative GGH's. The practical limitation came from the size of the single main SCR GGH – in Unit 2's case, this could require a rotary regenerative GGH with a rotor larger than the largest one ever built, in excess of 60 feet in diameter. Unit 2 has two existing wet FGD absorbers arranged in a parallel configuration, with

⁷⁷ Ibid Reference number 15, January 11, 2010*.

⁷⁸ Ibid Reference number 22, page 10, April 2010*.

⁷⁹ Ibid Reference number 9, November, 2009*.

each capable of handling slightly more than 50% of the maximum flue gas mass flow. With Unit 1's boiler having a maximum flue gas flow rate of approximately 60% of Unit 2's boiler, a single main SCR GGH design could effectively be used in all three locations – one for Unit 1 and two for Unit 2. This approach would avoid having the dubious distinction of purchasing and maintaining the first rotary regenerative GGH of a size not proven in utility powerplant or similar service. This arrangement also allows more site locations to consider for possible placement of the SCR reactor/GGH "tower", and commonality of subsystem equipment for design, procurement, installation, operation and maintenance between Unit 1 and Unit 2 boilers.

Other technical reasons for this SCR arrangement include ductwork sizes and being able to route flue gas to and from the two existing Unit 2 desulfurization system absorber inlet and outlet ducts independently. A single flue gas duct sized to handle the entire design volume of Unit 2's mass flow is 30 feet in diameter where it enters the new chimney's inlet breeching. Such large ductwork requires significant space for routing between the GGHs and the FGD scrubber absorber vessels, while considering such factors as pressure drop, flow patterns, structural supports and foundations, construction of new ductwork while the existing plant is operation, maintenance access to existing FGD scrubbers and new SCR reactors, including isolation and bypass dampers, rework of existing fiberglass reinforced plastic (FRP) and steel ductwork and tie-ins of such ductwork for rerouting the flue gas paths between the electrostatic precipitator outlet and the new chimney. Using a design approach compatible with the two existing FGD absorber vessels allowed the use of smaller ductwork. The twin reactor design allowed the flexibility to isolate each scrubber and SCR pair without compromising the other pair in case of problems with the scrubber tower, induced draft fan or booster fan, or SCR subsystem associated with that particular flue gas flow path. As previously stated in response to the EPA's comments, the objective was not to minimize capital cost but to create a conceptual design that considers many factors (i.e. be constructable, operable, reliable, maintainable, and meet performance requirements over the expected life of the equipment).

We also disagree with the DOJ's SCR consultant's comments that the use of heat exchangers for flue gas reheating associated with tail-end SCRs is "completely unnecessary"⁸⁰. The September, 2009 Fuel Tech document⁸¹ provided by Minnkota to the NDDH referenced by Hans Hartenstein in his April 2010 report included the following:

⁸⁰ Ibid Reference number 22, page7, April 2010*.

⁸¹ Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 328-329, February 2010*.

Flue Gas Heating & FGD GGH Options

For Tail End systems, it is important for the flue gas temperature entering the SCR GGH to be above the water dewpoint. This will prevent condensation and potential corrosion within the GGH. There are a few methods for raising the FGD outlet temperature:

- **FGD GGH:** Regenerative type heat exchangers have been used in Europe for this application. When FGD systems were deployed in German powerplants, heat exchangers were needed to raise flue gas temperatures to $>72^{\circ}\text{C}$ for plume buoyancy. These same exchangers were integrated into Tail End SCR systems. Some corrosion issues have been documented. Some solutions that have been used include alloy elements, plastic elements, and enameled elements.
- **FGD Heat Pipes:** Another type of heat exchanger is the heat pipe technology, such as that marketed by Hitachi. Hitachi has installed this type of exchanger in Japanese plants.
- **Flue Gas Heating with Duct Burners:** Direct gas firing in the duct would eliminate the need for a heat exchanger. In contrast to the use of duct burners for maintaining flue gas temperature to the inlet of the SCR catalyst, continuous gas firing would be needed for controlling the flue gas temperature at the inlet to the SCR GGH.
- **Heat Exchange Loop at the SCR GGH:** Another method includes the use of a slipstream from the SCR GGH outlet back to the inlet to raise the inlet flue gas temperature. This alternative is shown below in red:

What Hans Hartenstein failed to mention in his argument “Employing FGD-GGHs for flue gas drying upstream of the SCR-GGH is the most complicated and most costly possible arrangement. Again, B&McD doesn’t offer any rationale as to why this selection was made over the other options described in the Fuel Tech document...”⁸² was the recognition of the point that Fuel Tech made following the text section above:

The latter two methods would affect the overall mass balance of the Tail End system, primarily due to the increased natural gas consumption by the duct burners.

A cost-benefit comparison of these alternatives should be prepared specifically for the MRYS installation.

In developing the conceptual design of the hypothetical applications of LDSCR and TESCR technologies at MRYS, Burns & McDonnell initially relied on technical advice and preliminary mass/heat balance calculations provided by SCR consultants experienced in conventional, LD and TESCR SCR process design (formerly Tackticks, LLC, now part of Fuel Tech, Inc.). The experience and qualifications of the SCR consultants engaged by Burns & McDonnell in this effort, and issues associated with FGD GGHs on TESCR applications for utility boilers, were previously described in September 2008⁸³.

The configuration of the TESCR flue gas reheating heat exchangers developed for the hypothetical applications at MRYS located the main SCR rotary GGH immediately downstream of the FGD absorber flue gas outlet FGD heat exchanger. The intent of such an arrangement was to allow acid mist carryover (H_2SO_4)

⁸² Ibid Reference number 22, page 8, April 2010*.

⁸³ See Appendix A of Reference number 23 f., September 22, 2008*.

from the FGD outlet to condense within the FGD heat exchanger where it could be removed by suitable on-line cleaning, not in the main SCR GGH. Hans Hartenstein's report also failed to recognize that during a cold startup, when there is insufficient heat available from the utility boiler to supply a flue gas reheat steam heat exchanger but when coal is being fired in the boiler, there will be some acid condensation in the main SCR GGH for the TESCO configuration he describes. The European TESCO GGH arrangement may tolerate this situation, but they don't burn North Dakota lignite that has a significant amount of sodium-rich aerosol particles in the flue gas downstream of the FGD absorber outlet. These particles are shown to be sticky in nature (as documented in the Powerspan pilot test at MRYS Unit 1 previously reported⁸⁴) and would be expected to accumulate on heat transfer surfaces without on-line cleaning, and require periodic outages for deposit removal⁸⁵.

The FGD GGHs proposed in the hypothetical applications at MRYS proposed by an SCR system supplier were assumed to include materials of construction and added on-line cleaning equipment that would tolerate the expected flue gas conditions. BMcD has previously discussed concerns with the potential use of rotary regenerative GGHs for FGD outlet flue gas reheating upstream of the main TESCO GGH in the hypothetical applications at MRYS⁸⁶. The text from Fuel Tech's document included above was general in nature and was offered very near the end of the SCR cost estimate study project. The level of detail developed by Burns & McDonnell involving flue gas reheating equipment and arrangements for the SCR cost estimate study was sufficient for use in a NOx BACT analysis for MRYS boilers.

SCR Catalyst Exchange Frequency

We disagree with Hans Hartenstein's position that the NDDH's BACT Determination and November 2009 MRYS Supplemental NOx BACT Analysis Study reports relied upon "...completely arbitrarily selected catalyst exchange frequencies resulting from unknown and unsupported catalyst deactivation assumptions (B&McD's "Scenario B")"⁸⁷ for hypothetical applications of LDSCR and TESCO technologies at MRYS. Details of SCR catalyst deactivation mechanisms from sodium aerosols, and various examples of rapid deactivation after exposure to alkali-rich aerosols, have been previously described⁸⁸:

- Catalyst activity decreased by 52% after about 1140 hours of operation caused by biomass derived alkali rich aerosols (Zheng and others, 2005).

⁸⁴ Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence pages 277-280, February 2010* and Reference number 23, Supplemental Information for Consideration, February/March 2009*.

⁸⁵ See pages 3 and 4 of Appendix A of Reference number 23 f., September 22, 2008*.

⁸⁶ See Reference number 23h., page 42, and Reference number 23 i., February/March 2009.

⁸⁷ Ibid Reference number 22, page 10, April 2010*.

⁸⁸ Ibid Reference number 23 f., pages 11-13, November, 2008.

- Catalytic activity dropped by over 40% in testing ranging from 100 to 3000 hours due to increased levels of sodium and potassium aerosols accumulated in the SCR catalyst derived from the ultra fine particles in three biomass and peat fired 100 MW-scale combustion systems (Kling and others, 2007).
- Catalyst deactivation rate was about 18% per 1000 hours at a stoker-fired utility boiler firing a blend of biomass and Powder River Basin coal (PRB) (Strege and others, 2008).
- Relative reactivity decreased to 20%, or 80% deactivation after 1400 hours for a pulverized wood-fired boiler due to build up of potassium in the catalyst from the presence of highly reactive alkali (potassium and sodium) aerosols in the flue gas (Khodayari, 2001).
- Deactivation rate of about 1% per day of the relative activity was seen with operation of full-length monolith catalysts installed at a straw-fired power plant when the power plant ran continuously (Zheng and others, 2008).
- Avedore's Unit 2 power boiler which required SCR catalyst to be rejuvenated nine times and replaced once within the first 30,000 hours of operation, which included periods with and without biomass cofiring. Based on the publicly-available data, actual catalyst maintenance activities were much more significant than the above numbers imply, because they represent catalyst impairment resulting from exposure equivalent to approximately 1000 hours of estimated biomass co-firing operation between catalyst rejuvenation or replacement activities.
- Severe, rapid catalyst blinding and plugging due to sodium and potassium rich species from the only known example of simulating SCR catalyst exposure to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler (Coyote pilot-scale SCR test⁸⁹). This experience demonstrated the generation of alkali-sulfate compounds that plugged every micropore of the test catalyst when examined under a scanning electron microscope. This catalyst blinding and plugging was so severe that the catalyst vendor who supplied it was unwilling to analyze it for deactivation.

There is sufficient evidence from demonstrated catalyst exposures to alkali-rich flue gas, including those cited above, and catalyst vendor responses to Minnkota's 2009 Request for Proposal, which indicate that even in hypothetical low-dust and tail-end SCR applications considered for MRYS, there is the high potential for rapid deactivation and fouling of catalyst exposed to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler.

We reject the DOJ's SCR consultant's apparent attempt to link Burns & McDonnell's BACT determination recommendation for MRYS with an implication that it was tainted by a working relationship with "a consultant dedicated to SNCR for developing all of this technical SCR and catalyst information most critical

⁸⁹ See Reference number 24, October 2005.

for the overall cost estimate”⁹⁰. Burns & McDonnell engaged the referenced consultant in the second half of 2008 prior to the purchase of the referenced consulting firm (formerly Tackticks, LLC) by the current owner (Fuel Tech, Inc.). We sought help in this effort primarily because of the significant experience of the consultant’s principal (Volker Rummenhohl) involving conventional, low-dust and tail end SCR process design, commissioning, and operations and maintenance performance, not because the parent company’s primary business of selective non-catalytic reduction (SNCR) technology happened to coincide with Burns & McDonnell’s BACT determination for MRYS. The change in the referenced SCR consulting practice’s ownership occurred after the establishment of Burns & McDonnell’s BACT recommendation for MRYS, and was simply coincidental and not a relevant factor in technical arguments in favor of SNCR and against SCR being applied to the boilers at MRYS.

The effectiveness of catalyst to reduce NO_x emissions long-term in the hypothetical low-dust and tail end SCR applications at Young Station will be a function of a combination of factors. The most significant impacts previously presented (and not repeated in detail here) will be to reduce catalyst effectiveness resulting from fine aerosol of highly-concentrated alkali particles combining with sulfur and ammonia within the catalyst, causing rapid blinding and possible accumulation (plugging) in addition to chemical poisoning (deactivation)⁹¹. CERAM was not involved with the Coyote pilot-scale SCR testing, so it is not known how much influence their personal awareness of the character of the Coyote test’s fine particles and their tendency to penetrate catalyst pores and stick to catalyst surfaces had on their proposal and conceptual catalyst design for MRYS.

We believe that there is enough uncertainty expressed by catalyst vendors when presented with a comprehensive set of documents with details of specific coal and flue gas constituents, along with empirical evidence in the form of the Coyote pilot-scale SCR test results and MRYS Unit 1 pilot-scale Powerspan barrier reactor test results, to alter their willingness to guarantee catalyst life in the cases of hypothetical low-dust and tail end SCR applications at MRYS without having completed a successful long-term pilot test on these boilers burning North Dakota Lignite⁹². There are no current SCR applications in the world that are directly comparable to MRYS with cyclone boilers burning North Dakota lignite coal.

As previously stated, “[i]t is extremely imprudent to apply SCR to a utility boiler with such differences in firing type and fuel burned compared to those situations that have been proven successful without first performing extensive pilot testing and achieving acceptable results, followed by confirming the feasibility of the full-scale design. One cannot look just at the bulk flyash loading and average concentrations of the trace

⁹⁰ Ibid Reference number 22, page 11, April 2010*.

⁹¹ Ibid Reference numbers 7, 9, and 16, including Reference number 23 g., pages 18 and 19*.

⁹² Ibid Reference number 24, October 2005, and Ibid Reference number 23 g., November 2008*.

elements and other poisons in the fuel to decide whether SCR technology will work. It is incorrect to make a blanket statement that implies it is always feasible to install TESCO⁹³.

Catalyst is rarely replaced because the user knows precisely when it has reached the end of its design life; it is usually replaced during a scheduled outage when the opportunity is available. Because of the high potential for rapid deactivation and fouling of catalyst exposed to high-alkali containing flue gases produced from firing North Dakota lignite in a cyclone boiler causing significant uncertainty in catalyst life expectancy at MRYS, Burns & McDonnell estimated catalyst replacement frequencies and costs for Scenario "B" assuming that the MRYS boilers would be able to sustain typical baseload operation near maximum continuous ratings while achieving 30-day rolling average NOx emission rates at 0.05 lb/mmBtu on a year-round operating basis only if frequent, extended outages coinciding with scheduled boiler fireside cleanings were performed for catalyst maintenance. While these frequencies and conditions of SCR catalyst maintenance in the cases of hypothetical low-dust and tail end SCR applications at MRYS are more pessimistic than the DOJ's SCR consultant's opinions based on his experience with other boilers and fuels not similar to cyclone boilers burning North Dakota lignite and not requiring such high NOx emissions reduction as analyzed for MRYS, such catalyst maintenance activity frequencies are certainly possible when considering the unfavorable Coyote pilot-scale SCR test results and MRYS Unit 1 pilot-scale Powerspan technology test results and other biomass-related SCR catalyst deactivation data.

As for the DOJ's SCR consultant's April 2010 comparison of heat input and flue gas mass flow data⁹⁴, the design numbers cited as given to the two catalyst vendors involved with Minnkota's LDSCR and TESCO RFP in 2009 were improperly portrayed by Mr. Hartenstein. The ones listed in the consultant's comparison of the referenced April 2010 report are actually from the SCR Vendor Query issued by B&McD in April 2007. These earlier numbers were calculated separately from the 2009 SCR Cost Study, and were only provided in abbreviated form in the 2009 Minnkota LDSCR and TESCO RFP as a convenient reference. The two catalyst vendors were given preliminary mass balances of flue gas flows and constituents in August 2009 (the spreadsheets of March 11, 2009 as calculated by Fuel Tech). The numbers shown in the DOJ's SCR consultant's April 2010 report also do not accurately reflect values given to the responsive SCR system supplier (Babcock Power) in March 2009⁹⁵. Values given to Babcock Power by Burns & McDonnell in March 2009 shown by the DOJ's SCR consultant in a summary table⁹⁶ were taken from the preliminary mass balance spreadsheets as calculated by Fuel Tech dated March 11, 2009 for flue gas flows and constituents at the electrostatic precipitator outlet for the low-dust SCR cases, and the flue gas desulfurization system outlet

⁹³ Ibid Reference number 23 g., November 2008*.

⁹⁴ Ibid Reference number 22, pages 19 and 22, April 2010*.

⁹⁵ Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence, pages 40-43, February, 2010.

⁹⁶ Ibid Reference number 16, Enclosure C Non-Confidential Vendor Correspondence, page 43, February, 2010.

for the tail end SCR cases, assuming two reactors per boiler. It is obvious that Mr. Hartenstein has incorrectly portrayed this preliminary design basis assumed by the catalyst vendors.

We provided Fuel Tech with appropriate and available information regarding inputs to be assumed for the LDSCR and TESCO preliminary design basis of the hypothetical applications for MRYS. Maximum and normal full load boiler gross heat input rates, coal analyses, boiler outlet oxygen concentration (wet basis), and air inleakage percentage downstream of the boiler and calculated values of flue gas mass flows and constituents (without sulfur trioxide) were provided to Fuel Tech in January 2009 for their preliminary mass balance calculations. We did not assume any SO_3 concentrations because we did not have values for that parameter at MRYS, and because accurate measurements of this constituent involve significant effort, this is not typically measured in routine stack emissions testing. As the amount of SO_3 in the flue gas depends on interactions of sulfur with other gases and entrained particulate within the boiler and downstream treatment processes, we deferred to the catalyst vendors to assume or determine what they felt was an appropriate SO_3 concentration.

It should be pointed out that it is common engineering practice to design flue gas handling equipment based upon maximum expected values (i.e. short-term conditions) but to calculate operating costs of running that equipment based upon values that reflect sustainable averages. We used Haldor Topsoe's LDSCR and TESCO preliminary catalyst and reactor design of the hypothetical applications for MRYS, along with HTI catalyst unit pricing, as inputs to calculations of long-term annual operating costs in the November 2009 Supplemental NOx BACT Analysis Study reports for MRYS. Using current (2009 or 2010) catalyst prices would not be consistent with the 2006 basis assumed for the original NOx BACT Analysis Study reports for MRYS of non-SCR NOx control alternatives. We did not request catalyst proposals from Johnson Matthey Catalysts (JMC, formerly Argillon/Siemens) due to previous lack of responses to our 2007 SCR Vendor Query and 2008 followup.

There are numerous discrepancies contained in the page 22 comparison table of the DOJ's SCR consultant's April 2010 report. The correct values given by B&McD to the SCR system supplier (Babcock Power) and the two catalyst vendors are included in the table below:

B&McD SCR Design Criteria and Values Provided to Vendors

LDSCR MRYS U1		2009 SCR RFI	2007 SCR Vendor Query ⁹⁷
Gross heat input	mmBtu/hr	2,955	2,852
Process Location		ESP Outlet	Boiler Outlet
Flue gas mass flow	Lb/h	3,479,112	3,811,000
Volume flow rate	ACFM	1,130,518	2,502,000 (@910°F)
Volume flow rate	Nm3/h, wet	1,232,884	—
SO ₂ inlet concen.	Lb/mmBtu	1.93 (calc)	3.0
SO ₂ mass flow	Lb/h	5,691 ⁽¹⁾	8,970 ⁽²⁾
		Reactor Inlet	—
Flue gas mass flow	Lb/h	3,680,676	—
Volume flow rate	ACFM	1,566,538	—
Volume flow rate	Nm3/h, wet	1,305,184	—
SO ₂ inlet concen.	Lb/mmBtu	2.0	—
SO ₂ mass flow	Lb/h	5,907	—
TESCR MRYS U2		FGD Outlet	Boiler Outlet
Gross heat input	mmBtu/hr	5,158	4,740
Flue gas mass flow	Lb/h	6,458,832	7,117,000
Volume flow rate	ACFM	1,641,826	4,371,000 (@818°F)
Volume flow rate	Nm3/h, wet	2,361,164	—
SO ₂ inlet concen.	Lb/mmBtu	0.096	3.0
SO ₂ mass flow	Lb/h	496 ⁽¹⁾	15,474 ⁽³⁾
		Reactor Inlet	—
Flue gas mass flow	Lb/h	6,832,108	—
Volume flow rate	ACFM	2,989,916	—
Volume flow rate	Nm3/h, wet	2,497,840	—
SO ₂ inlet concen.	Lb/mmBtu	0.01	—
SO ₂ mass flow	Lb/h	514	—

Notes:

(1) SO₂ emissions calculated by Fuel Tech are less than the nominal and normal maximum values based upon 7.5% higher than long-term average, and 90th percentile lignite coal sulfur contents, respectively (from the Center mine). Unit 1 SO₂ at ESP outlet should have been stated as 11,368 lb/h or 3.85 lb/mmBtu, based upon 90th percentile as-received coal sulfur content of 1.3% and calculated higher heating value of 6,767 Btu/lb. Unit 2 SO₂ at FGD outlet should have

⁹⁷ See Reference number 23 e., May 2007.

been stated as 992 lb/h or 0.19 lb/mmBtu, based upon 90th percentile as-received coal sulfur content of 1.3% and calculated higher heating value of 6,767 Btu/lb and 95% removal by wet FGD. See Reference number 23 e., May 2007.

(2) Expected Boiler Outlet Maximum 30-day average SO₃ was 135 lb/hr for U1, based upon assuming 1.5% conversion of the boiler outlet SO₂, 2,990 mmBtu/hr heat input, 1% sulfur in lignite coal with 6,578 Btu/lb higher heating value.

(3) Expected Boiler Outlet Maximum 30-day average SO₃ for U2 of 236 lb/hr, based upon assuming 1.5% conversion of the boiler outlet SO₂, 5,158 mmBtu/hr heat input, 1% sulfur in lignite coal with 6,578 Btu/lb higher heating value.

Upon review of the SCR process design values provided in the table above, we noticed that SO₂ emissions in the preliminary mass balance spreadsheets given to the SCR system supplier and the two catalyst vendors were inadvertently underestimated by a substantial margin. Underestimating SO₂ emissions could cause an underprediction of SO₂ to SO₃ conversion by the catalyst vendors, and lead to overprediction of catalyst life. Burns & McDonnell did not attempt to correct or advise the vendors of these discrepancies because they were found after proposal submittals. Both catalyst vendors appear to have calculated SO₂ emissions rather than using the values provided in Fuel Tech's March 2009 LDSCR and TESCO preliminary design basis spreadsheets.

SCR Design Criteria and Values Provided by Vendors

MRY5 U1		CERAM	Haldor Topsoe
Gross heat input	mmBtu/hr	(1)	2,852
Process Location		LDSCR Reactor Inlet	LDSCR Reactor Inlet
Flue gas mass flow	Lb/h	3,684,000 ⁽²⁾	3,811,000
Volume flow rate	ACFM	(1)	(1)
Volume flow rate	Nm3/h, wet	(1)	(1)
SO ₂ inlet concn.	Lb/mmBtu	(1) [4.00] ⁽³⁾	(1) [3.15] ⁽⁴⁾
SO ₂ mass flow	Lb/h	(1) [11,826] ⁽³⁾	8,970 ⁽⁴⁾
MRY5 U2		TESCO Reactor Inlet	LDSCR Reactor Inlet
Gross heat input	mmBtu/hr	(1)	4,740
Flue gas mass flow	Lb/h	6,838,286 ⁽²⁾	7,117,000
Volume flow rate	ACFM	(1)	(1)
Volume flow rate	Nm3/h, wet	(1)	(1)
SO ₂ inlet concn.	Lb/mmBtu	(1) [0.20] ⁽³⁾	(1) [3.26] ⁽⁴⁾
SO ₂ mass flow	Lb/h	(1) [1030] ⁽³⁾	15,474 ⁽⁴⁾

Notes:

(1) Value not included in vendor quote.

(2) Calculated by multiplying vendor mass flow in kg/h by 2.2046 lb/kg. Unconfirmed by the vendor.

(3) SO₂ mass rate calculated by multiplying vendor SO₂ concentration in mg/Nm³ by Fuel Tech's Nm3/h volume flow rate at reactor inlet, then multiplied by 2.2046 lb/kg and divided by 1,000,000 mg/kg. SO₂ inlet concentration in lb/mmBtu calculated by dividing lb/h mass rate by assumed gross heat input rate of 2,955 mmBtu/h for Unit 1 and 5,158 mmBtu/h for Unit 2. Unconfirmed by the vendor.

(4) SO₂ mass rate at LDSCR reactor inlet should have been stated as 10,980 lb/h for Unit 1 and 18,249 lb/h for Unit 2 assuming 3.85 lb SO₂/mmBtu, based upon 90th percentile as-received coal sulfur content of 1.3% and calculated higher heating value of 6,767 Btu/lb. SO₂ inlet concentration in lb/mmBtu calculated by dividing lb/h mass rate by stated gross heat input rate of 2,852 mmBtu/h for Unit 1 and 4,740 mmBtu/h for Unit 2. Unconfirmed by the vendor.

Because of the numerous instances where values contained in the page 22 comparison table of the DOJ's SCR consultant's April 2010 report do not agree with the values provided by Burns & McDonnell in August 2009, we recommend that the NDDH reject the arguments presented by Mr. Hartenstein involving this information.

We disagree with Mr. Hartenstein's mischaracterization of Burns & McDonnell's January 2010 letters⁹⁸ that the two catalyst vendors engaged in the 2009 Minnkota LDSCR and TESCO RFP were "offered" pilot scale testing in order to be able to guarantee initial catalyst life. The intention of Burns & McDonnell's letter was to properly capture the substantive caveat these catalyst vendors included in their confidential proposals without having to redact their proposals. We were unaware at the time that Burns & McDonnell issued their proposal clarification letters that the vendors would be subsequently asked by others and agree to redact their confidential proposals to allow public disclosure.

We wish to point out the three catalyst vendors, cited by Mr. Hartenstein as responsive to his June 2008 request to provide commercial guarantees for catalyst life for a TESCO at MRYs without requiring pilot testing, were not provided a detailed flue gas, coal, and ash analysis or detailed design basis when they made those responses. Two of those three catalyst suppliers were provided such details in August 2009 via Minnkota's LDSCR and TESCO RFP and subsequently declined to guarantee catalyst life unless pilot testing were successfully completed. These two catalyst vendors, with significant global catalyst experience on coal-fired boilers, when provided with detailed measured aerosol particulate data as part of a request to consider a new SCR application of North Dakota lignite fired in MRYs cyclone boilers, indicated that they would require successful pilot testing before being willing to offer catalyst life guarantees. We conclude that the catalyst vendors carefully examined the information provided and referenced for review, including fuel, ash, and aerosol data from MRYs, and recognized the difficulties in predicting the ability of the catalyst to maintain performance under such conditions without having actual experience with such combinations of sulfur, ammonia, and ultrafine particulate enriched in sodium and other known catalyst poisons and blinding agents.

Mr. Hartenstein incorrectly assumes that actual measured particulate mass rates from stack tests should be used as the basis in preliminary LDSCR and TESCO process designs. The preliminary design approach taken

⁹⁸ Ibid Reference number 16, pages 377-380, February 2010.

by Burns & McDonnell for Minnkota's hypothetical applications of LDSCR and TEGSR technologies for MRYS was to assume the permissible limit for particulate mass per unit of heat input emissions from the ESPs (0.03 lb/mmBtu) as required in Minnkota's April 2006 Consent Decree⁹⁹ for MRYS Unit 1 and Unit 2 with wet FGD systems. Electrostatic precipitator hourly average outlet mass particulate outlet emissions were assumed as 0.03 lb/mmBtu x 2,955 mmBtu/hr = 88.7 lb/hr for Unit 1 and 0.03 lb/mmBtu x 5,158 mmBtu/hr = 155 lb/hr for Unit 2.

MRYs U1		CERAM	B&McD / Fuel Tech
Process Location		LDSCR Reactor Inlet	LDSCR Reactor Inlet
Particulate mass flow	Lb/h	$37.0^{(1)} \times 2 = 74$	$89 / 35 \times 2 = 70^{(2)(3)}$
MRYs U2		CERAM	B&McD / Fuel Tech
Process Location		TEGSR Reactor Inlet	LDSCR Reactor Inlet
Particulate mass flow	Lb/h	$80.0^{(1)} \times 2 = 160$	$155 / 77 \times 2 = 154^{(2)(3)}$

Notes:

(1) Particulate emission rate is per reactor assuming two reactors per Unit, so correct total is double the amount CERAM noted in their proposals.

(2) Calculated by multiplying design maximum average boiler heat input rate (million Btu per hour) by the maximum average particulate loading (pound per million Btu) to give lb/h particulate emission rates. The Fuel Tech March 11, 2009 preliminary mass balance spreadsheets list 35 lb/hr x 2 for Unit 1 and 77 lb/hr x 2 for Unit 2 at ESP outlets.

(3) Value not included in vendor quote.

Upon review of the SCR process design values provided in the table above, we notice that average hourly mass particulate emissions in the preliminary mass balance spreadsheets given to the two catalyst vendors for Unit 1 were inadvertently underestimated by approximately 17 percent ($37 \times 2 = 74$ lb/h instead of 89 lb/h). CERAM appears to have misstated the mass particulate emissions in their initial and updated proposals in response to Minnkota's August 2009 LDSCR and TEGSR RFP by a factor of two, but have assured Burns & McDonnell that the smaller values shown in the table above were used in their catalyst design calculations on a per reactor basis as provided in the Fuel Tech LDSCR and TEGSR preliminary design basis spreadsheets (dated March 11, 2009). Average hourly mass particulate emissions given to Babcock Power (responsive SCR system supplier) were inadvertently underestimated by approximately 21 percent for Unit 1 ($35 \times 2 = 70$ lb/h instead of 89 lb/h).

Microbeam Technologies report on MRYS Unit 2's measured flue gas particulate emissions

We reject many statements made by Mr. Hartenstein in his April 2010 report regarding the MRYS Unit 2 aerosol particulate testing performed in March 2009 and the Microbeam Technology July 2009 report summarizing the results of the analyses of the samples obtained from these tests.

⁹⁹ Ibid Reference number 8, pages 24 and 25, April 2006.

Mr. Hartenstein's premise that "it is conceivable that the higher particulate concentrations found during the MTI testing compared to the stack testing results since 2005 can be attributed to higher than design flue gas velocities and excessive droplet carryover from the FGD absorber"¹⁰⁰ is unsubstantiated. Many of the reasons postulated by the DOJ's SCR consultant are not proven to be valid for the MRYS case. There could be other valid reasons why particulate loadings at the Unit 2 FGD absorber outlets measured in 2009 are higher than those measured at the stack in 2008. The primary reason is that the stack and aerosol tests were not done simultaneously and thus were performed in different time periods under different firing/load, fuel, ash, and particulate collection conditions. Comparisons of the sort presented by Mr. Hartenstein are speculative and not particularly useful when discussing the details of aerosol particulate emissions reported from Minnkota's Unit 2 boiler.

The penetration of fine particulate through dry ESPs and wet scrubbers has been presented in previous responses¹⁰¹. The DOJ's SCR consultant incorrectly implies that Minnkota's Unit 2 FGD absorbers (two units in parallel) do not have wall rings to enhance sulfur and particulate removal efficiencies. In fact, Minnkota's existing scrubbers do have wall rings and high efficiency outlet mist eliminators. Particulate carryover from MRYS wet scrubbers was measured (at one of the absorber's outlet ports) with the flue gas bypass dampers closed, simulating conditions similar to those that will exist in 2011 and beyond after current ductwork modifications and new chimney under construction are completed in late 2010.

Mr. Hartenstein reviewed the work conducted by Kling and others (2007) who conducted research which found significant catalyst deactivation due to the accumulation of alkali elements in a hot side application. Kling and others (2007) found a correlation between the ultrafine particles and alkali (sodium and potassium) accumulation in the SCR catalysts that were exposed to flue gas derived from firing various types of biomass feedstocks. The following is a quote from the Kling paper

*"The study has shown a linear correlation between exposure time in the boilers and alkali concentration (mainly potassium) on the samples. The results **imply** that mainly alkali in ultra fine particles (<100 nm) in the flue gas increased the alkali accumulation on the catalyst samples. Low correlation was found between particles larger than 100 nm and the catalyst deactivation."*

Mr. Hartenstein elaborated on the results and conclusions drawn by Kling and others (2007) by making the following statement.

¹⁰⁰ Ibid Reference number 22, page 26, April 2010.

¹⁰¹ See Reference number 23 h., pages 18-22, February 2009.

Based on very extensive work and testing done by Kling et. al.²⁵, only the sodium and potassium bearing aerosols of the size fraction of less than 0.1 μm are of critical importance for catalyst deactivation while Kling found that the ones larger than 0.1 μm in size can be considered largely irrelevant for catalyst deactivation.

The work was not that extensive and nowhere in the referenced paper did Kling and others (2007) indicate that the larger particles are “largely irrelevant for catalyst deactivation” as elaborated by Mr. Hartenstein. Kling and others (2007) did not report that the particles larger than 0.1 μm were unimportant. They just did not find a good correlation. The dataset that they had was not sufficient to make good correlation. Kling and other (2007) indicated that they are uncertain in their correlations made between the impactor mass in the various size fractions and alkali accumulation and qualify the correlations made with the following statement:

“The uncertainty in the correlation between the impactor measurements and the alkali accumulation on the catalyst samples were however large. Only one or two impactor measurement of flue gas composition, each with about 20 min sampling time, has been conducted for each catalyst exposure season—in total up to 3000 h.”

Kling and others (2007) conducted testing in a high dust location and could not specifically separate the impacts of the ultrafine sized particles from the larger particles. Figure 1 shows the mass size distribution of the ash particles collected from the flue gas when firing various biomass material. Note that the highest abundance of particles on a mass basis is between 0.1 μm and 1 μm , not at the 0.1 μm (100 nm).

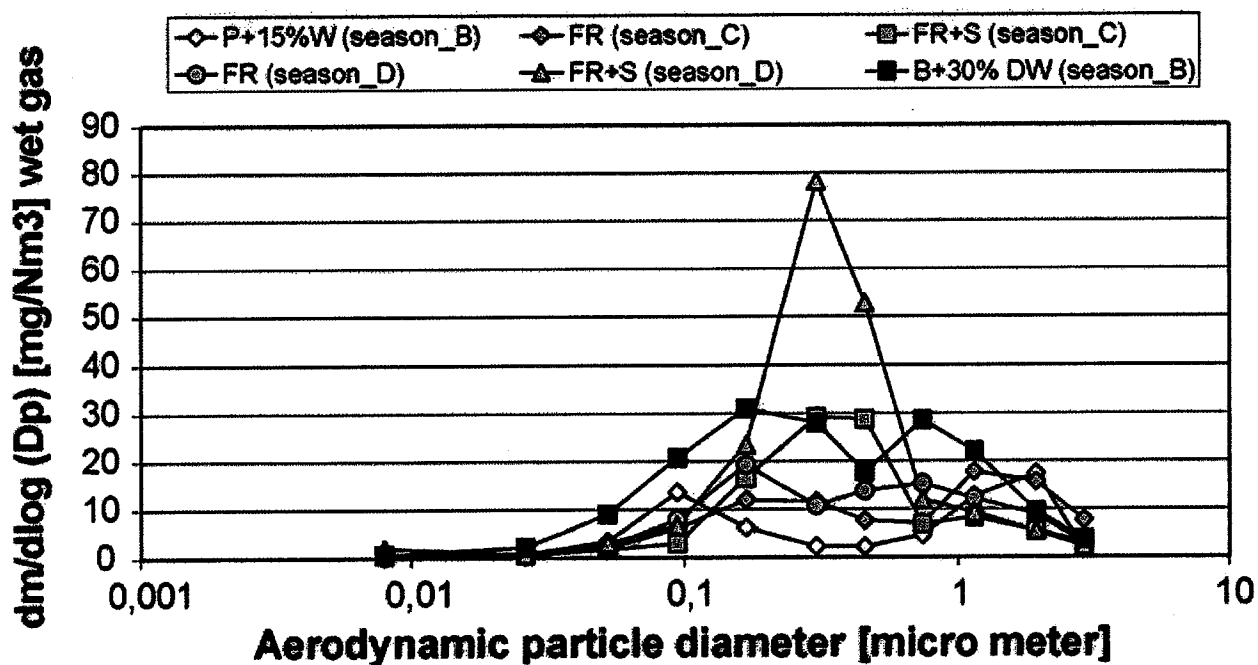


Figure 1. Mass size distribution of ash materials collected from flue gas from biomass fired system (Kling and others, 2007).

The abundance of the sodium, potassium, calcium, chlorine, and phosphorus were plotted as a function of size for the ash materials collected from the flue gas is shown in Figure 2. The results show that there is a

significant variation in the abundance of the components as a function of size and the highest concentrations were found between 0.1 and 1.0 μm . The deactivation of catalyst is shown in Figure 3 indicating range in the degree reduction in catalyst activity.

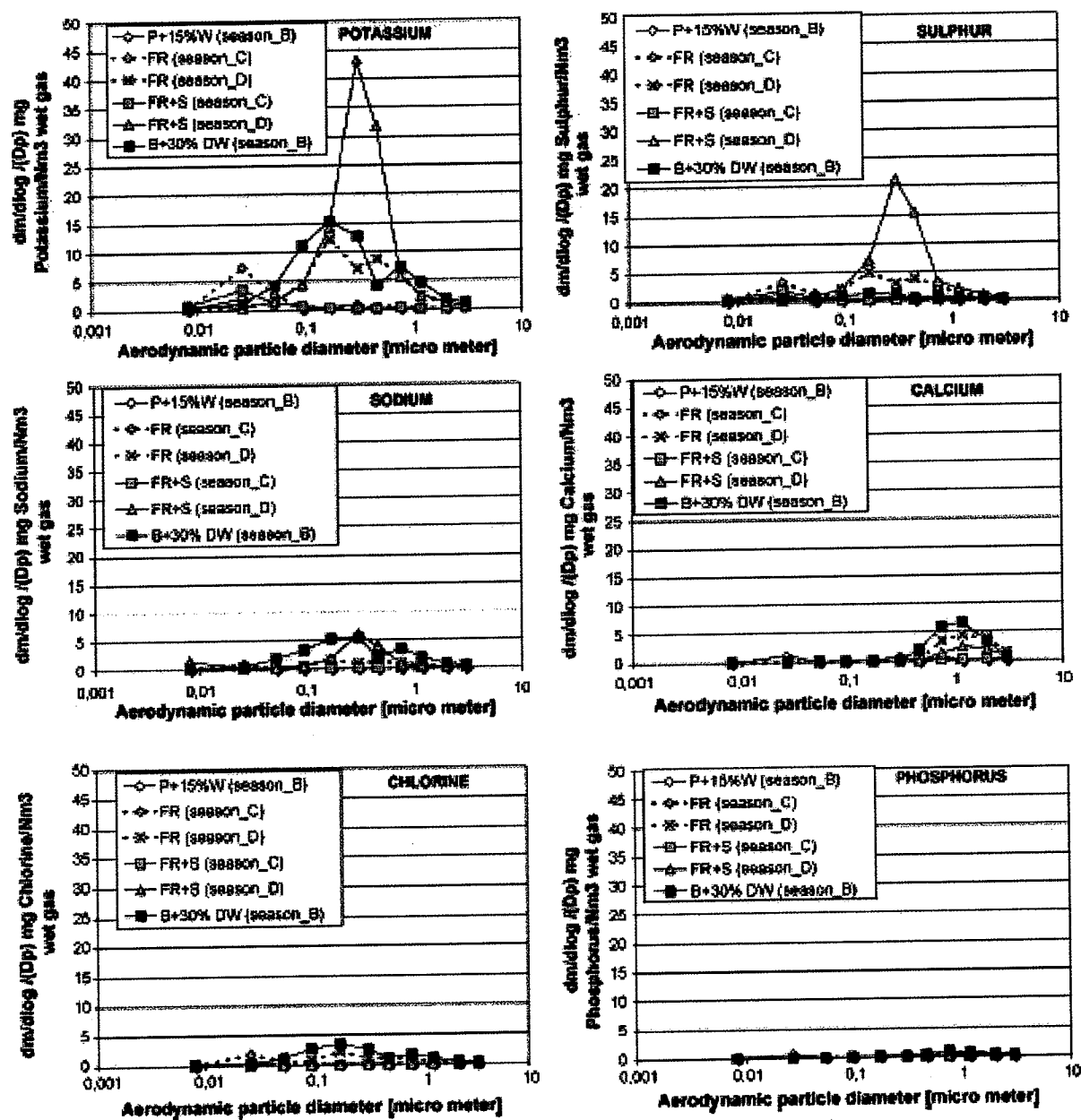


Figure 2. Fly ash mass size distribution (mg/N m3) for potassium, sodium, chlorine and sulphur, lead, zinc, phosphorus and calcium: P, peat; W, wood; FR, forest residues; B, bark; DW, demolition wood (Kling and others, 2007).

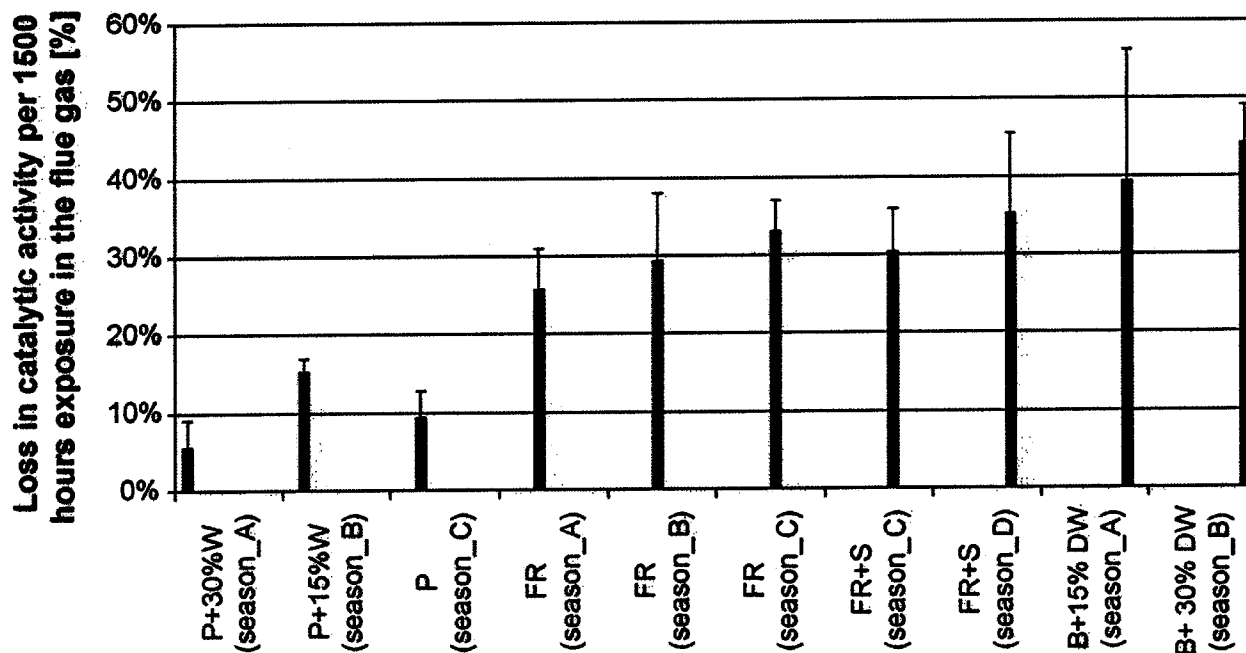


Figure 3. Catalyst deactivation per 1500 hours for various flue gases produced from biomass (Kling and others, 2007).

The impact of the intermediate or fine mode (0.5 to 1 μ m) of particulate materials on accumulation in the SCR catalyst and catalyst deactivation cannot be ruled out as suggested by Hartenstein. Mr. Hartenstein ignored past peer reviewed literature on the impacts of intermediate fine particulate mode (0.5 to 1 μ m) on catalyst performance. Of specific interest is a study of SCR catalyst deactivation when exposed to flue gas derived from a biomass grate fired system conducted by Zheng and others, 2005. They found significant catalyst deactivation for ash particles just under 1 μ m in diameter. The mass size distribution of the ash produced from grate-fired biomass fired system contained mostly the fine or intermediate mode of particles (0.5 to 1 μ m) as illustrated in Figure 4. They used a Berner-type low pressure impactor that could aerodynamically classify particle from 0.028 to 12.8 μ m. The Berner-type impactor is similar to Dekati impactor used by UND in the Microbeam study (Laumb and others, 2009). The reason for the lack of ultrafines is likely due to lower combustion temperatures and the bed burning environment found in a grate fired system. These intermediate mode or fine particles in the 0.5 to 1 μ m range were found to have a significant impact on the reactivity of the SCR catalyst as illustrated in Figure 5 where the reactivity dropped by 52% in about 1140 hours of exposure. This is evidence that the deactivation of SCR catalyst is not limited to only the ultrafine particles but the larger 0.5 to 1 μ m particles are equally or more important.

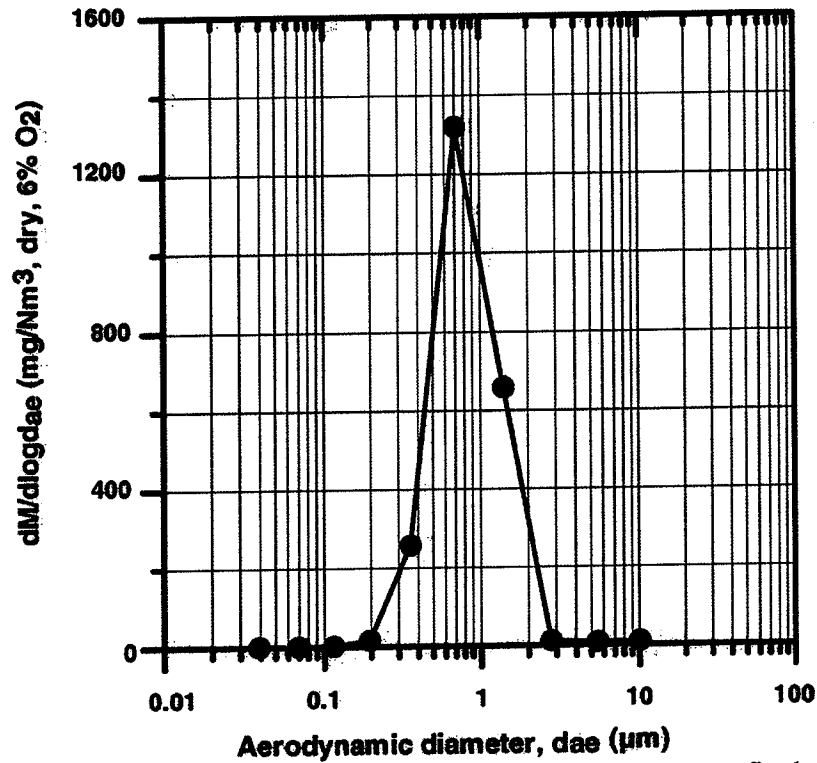


Figure 4. Size distribution of particles collected from a grate fired biomass system (Zheng and others, 2005).

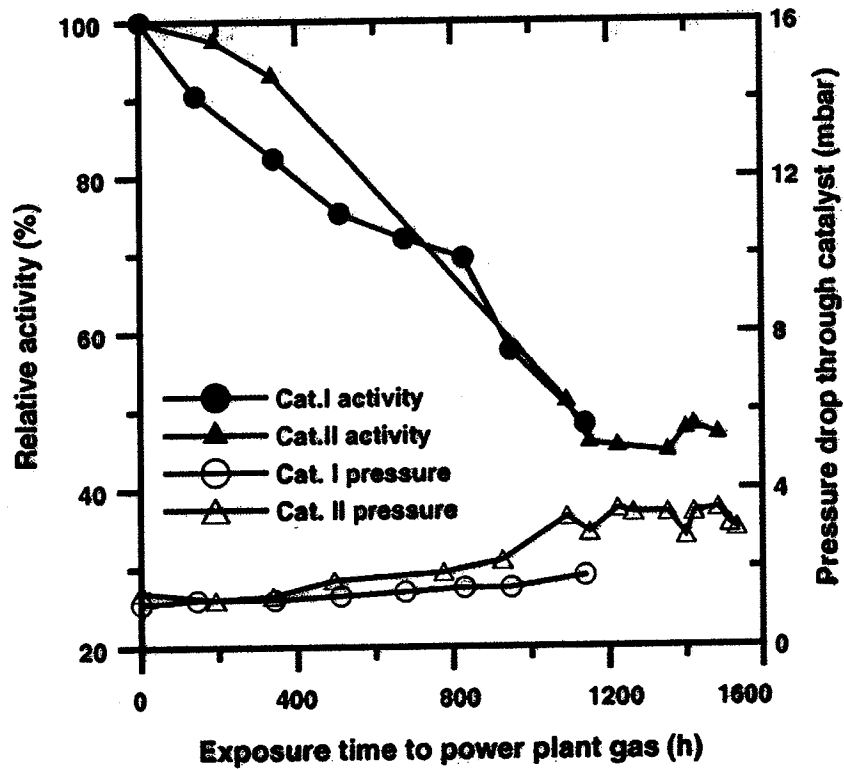


Figure 5. The activities of SCR catalysts and pressure drops over catalysts as a function of exposure time to power plant flue gas (Zheng and others, 2005).

The mass size distribution of the particles produced in the grate fired system (Figure 4) is slightly larger than that found for the exit of the MRY Unit 2 scrubber as shown in Figure 6. This is evidence that the particles in the size range of 0.5 to 1 μm exiting the MRY 2 scrubber cannot be ignored as suggested by Hartenstein and have the potential to impact catalyst performance.

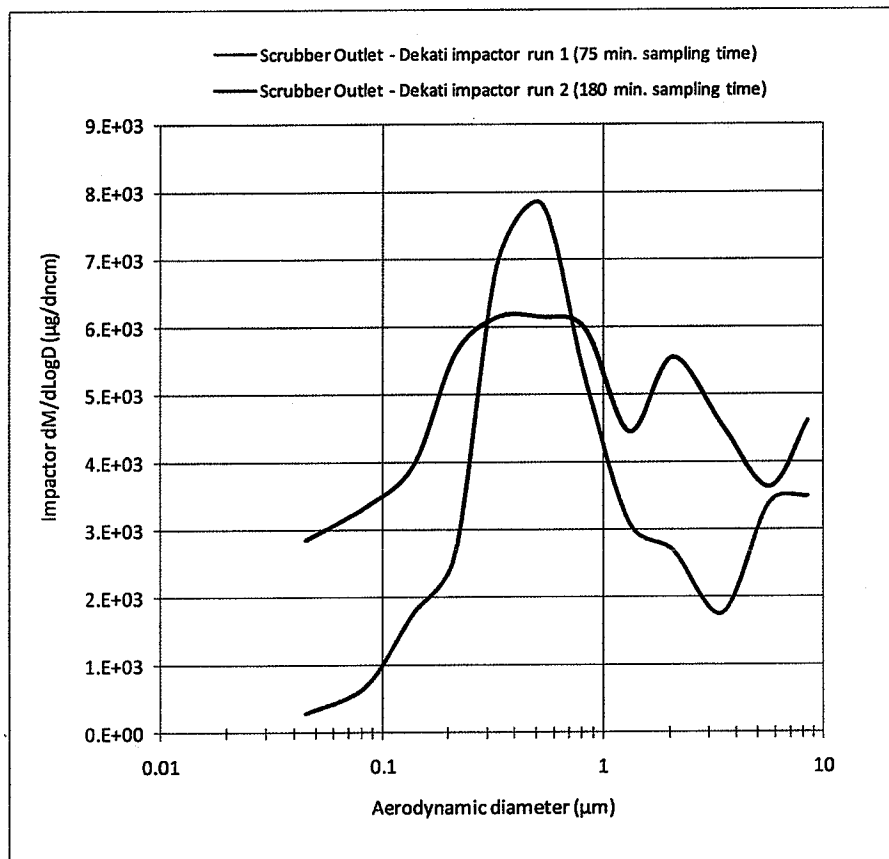


Figure 6. Mass size distribution for the ash collected downstream of the scrubber (Laumb and others, 2009).

Hartenstein appears to be relying heavily on the work by Markowski and others (1983) in his April 2010 report¹⁰² and with reference to his March 2010 SCR catalyst vendor inquiry. This earlier work must be used with caution and puts into question the validity of Hartenstein's March 2010 SCR catalyst vendor inquiry. The Markowski and others (1983) work is consistent with the sampling effort at MRY Unit 2 scrubber summarized in the 2009 Microbeam report (Laumb and other, 2009) in that the concentration of the fine particle emissions at the scrubber exit for one of the tests was 8800 $\mu\text{g}/\text{m}^3$ at a coal ash content of 8.41% and the work of Laumb and others (2009) was 10,000 $\mu\text{g}/\text{m}^3$ at an ash content 7.8%. The referenced 2009 Microbeam report indicated an average ash content in lignite of 8.41 % ash, which is typical of the ash content of lignite fired at the plant of 9.5%. Future projections for fuel quality range from 8.4 to 9.5% on an

¹⁰² Ibid Reference number-22, page 34, April 2010.

as-received basis as illustrated in Figure 7. North Dakota lignite coals having higher ash contents of between 12 and 19% were fired when much of the earlier testing was conducted by Markowski and others (1981). These higher ash lignites will produce lower levels of less than 1 μm particulate as compared to the lower ash coal because of the abundance and form of the inorganic components in the North Dakota lignite described in detail in Appendix C of the report by Laumb and others (2009). For the high ash coals, Markowski and others (1983) measured the levels of particulate at the scrubber outlet to be 2500 $\mu\text{g}/\text{m}^3$; these coals are currently not fired without blending with lower ash coal to decrease the ash content because of challenges with cyclone performance. Fuel properties are managed to maintain an ash level and base-to-acid ratio that allows optimum performance of the cyclone fired combustion system. Relying on the particulate measurements made by Markowski and others (1983) on the high ash lignite as it appears that Hartenstein did in his 2010 SCR vendor inquiry does not represent the current and future fuels fired at the plant.

In addition, Hartenstein's comment "Appendix C [of the Microbeam report, July 2010] is merely a regurgitation of mostly irrelevant information"¹⁰³ indicates that he does not consider the forms and abundance of the inorganic components in North Dakota lignites as being important. This is a **major oversight** of Hartenstein in that the forms and abundance of the inorganic species in lignite have played a major role in the design as well as the feasibility of technologies that utilize North Dakota lignites. For example, the size of pulverized coal-fired boilers is much larger for high sodium lignite boilers than for subbituminous or bituminous fired systems. The larger size of the boiler allows for more cooling of the products of combustion to minimize fouling and slagging of the upper furnace waterwalls and convective pass superheater/reheater tubes. Further, pilot testing of Powerspan's barrier discharge reactor used for multipollutant technology at MRYS was found to be severely impacted by sodium aerosols.

¹⁰³ Ibid Reference number 22, page 34, April 2010.

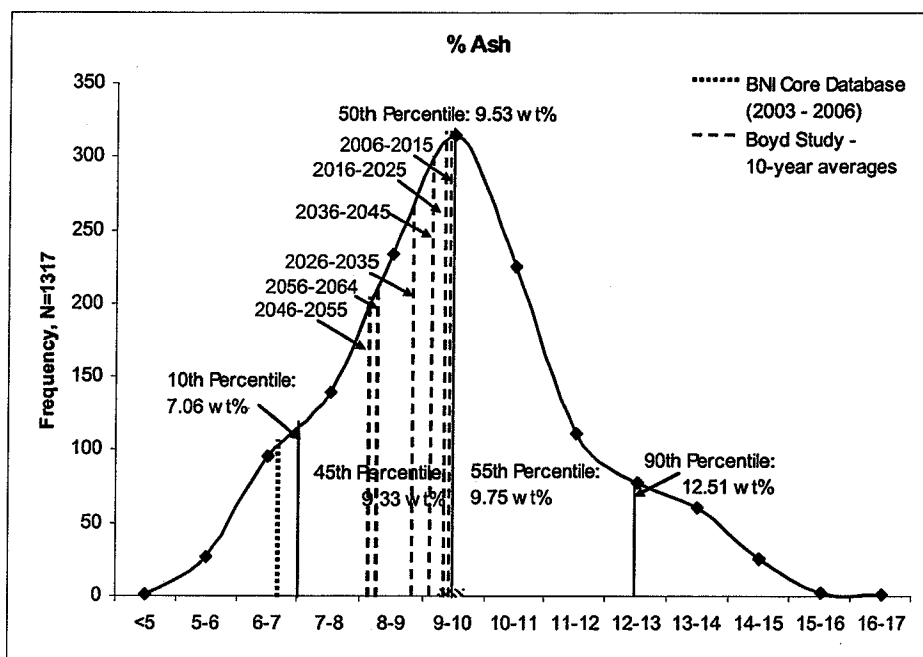


Figure 7. Ash content of lignite fired at MRYS and future projected blend based on core database.

Responses to DOJ's SCR Consultant's Individual Comments to NDDH's January 2010 Request

Responses to Comments to NDDH Request #1

We recommend that the NDDH ignore the majority of the DOJ's SCR consultant's comments for this item because they do not address the questions raised by the NDDH's request. Comments about the SCR system supplier that Burns & McDonnell selected for the Minnkota budgetary proposal of the hypothetical LD and TESCR system attempt to portray the vendor as inexperienced in low-dust SCR applications. Burns & McDonnell mentioned the SCR system supplier in the December 2009 response¹⁰⁴ primarily because of the relevance to the vendor's recent involvement on the WE Energies South Oak Creek LDSCR project, which initially began (conceptually) as a tail end SCR approach.

Much of the commenter's discussion focused on Burns & McDonnell's approach of using natural gas for flue gas reheating. Reasons for this selection were documented in the December 11, 2009 response to the NDDH¹⁰⁵. For Minnkota's 2009 capital cost estimate and supplemental BACT analysis of the hypothetical LD and TESCR systems, a system using recirculated hot air applying electric resistance heaters was assumed for heating the closed SCR reactor and catalyst to avoid moisture condensation during boiler outages. This electric heat/air recirculation system was expected to operate during startups and shutdowns along with the natural gas-fired main reheat burner system to maintain flue gas temperature control.

¹⁰⁴ Ibid Reference number 13, page 2, December 2009.

¹⁰⁵ Ibid, pages 3-7, December 2009.

Responses to Comments to NDDH Request #2

Reasons for this selection were documented in the February 11, 2010 response to the NDDH. See additional discussion regarding use of urea versus anhydrous ammonia under item 2 of the section “Responses to EPA Comments on SCR Annual Cost Estimates and Methods” on page 12 herein.

Responses to Comments to NDDH Request #3

Reasons for the catalyst replacement duration outage assumptions were summarized in the February 11, 2010 response to the NDDH. Because of the nature of scheduled boiler cleaning outages taking place during all seasons of the year, it should be noted that ambient weather conditions can also have significant impacts beyond catalyst reactor interior design, access, and replacement catalyst handling system design assumptions involving catalyst replacement duration. We know of no examples of SCR catalyst being replaced at existing installations in the middle of winter as severe as often experienced in North Dakota, which can frequently see subzero ambient temperatures, - winds of 30 miles per hour and greater, with significant snow accumulations. The low-dust and tail end SCR reactors were assumed to not be totally enclosed inside a heated building for the purposes of Minnkota’s 2009 capital cost estimate and supplemental BACT analysis of the hypothetical LD and TESCO systems. See additional discussion under item 3 of the section “Responses to EPA Comments on SCR Annual Cost Estimates and Methods” on page 12 herein regarding the number of additional outage hours not being solely a matter of catalyst replacement duration and frequency.

Responses to Comments to NDDH Request #4

We recommend that the NDDH ignore the majority of the DOJ’s SCR consultant’s comments for this item because they do not address the questions raised by the NDDH’s request. Explanation of the estimated indirect capital costs was summarized in the November 2009 Supplemental NOx BACT Analysis Study reports, December 11, 2009 and February 11, 2010 responses, and December 21, 2009 presentation to the NDDH, with additional discussion presented earlier in this response document.

Much of the commenter’s discussion focused on Burns & McDonnell’s project schedule for completion of hypothetical LD and TESCO systems for MRYS Unit 2 by year-end 2016 and by year-end 2017 for Unit 1. This schedule assumed that extensive slip-stream pilot-scale catalyst testing would be required and nearly completed before SCR system selection could be confirmed and design finished. There are also significant additional challenges that would be faced in retrofitting low-dust and tail end SCRs at MRYS involving:

- scheduling of placement of major equipment structural foundations to avoid winter weather;
- large rotary regenerative flue gas-gas reheating and induced draft fan equipment design, procurement, and field assembly/erection;

- design, procurement, field assembly/erection of modifications to existing/replacement of sections of large fiberglass-reinforced flue gas ductwork;
- coal storage and handling modifications and installations;
- flyash storage and handling modifications and installations.

None of the schedule examples cited by Mr. Hartenstein involved low-dust or tail end SCRs. The amount of time claimed to be required to execute retrofit SCR projects does not mention whether extensive slip-stream pilot-scale catalyst testing programs, with design and procurement of SCR system equipment of suitable scale and ability to simulate full-scale operation was required, nor the time to perform long-term testing, analyze the test catalyst, and report the results.

Responses to Comments to NDDH Request #5

We recommend that the NDDH ignore the DOJ's SCR consultant's comment for this item because it does not reflect or consider the assumption that the cost effectiveness analysis in the November 2009 Supplemental NOx BACT Analysis Study reports used the power industry's natural gas unit cost forecasts from 2006, in order to be consistent with the cost effectiveness analysis performed and reported in October 2006 for the non-SCR alternatives that involve consumption of natural gas.

Responses to Comments to NDDH Request #6

We recommend that the NDDH ignore the DOJ's SCR consultant's comments for this item. The comments do not reflect or consider the reasons for the preliminary design basis and assumptions involved with [estimating the capital and operating/maintenance costs for] retrofitting low-dust and tail end SCRs at MRYS that have been presented earlier in this document.

Responses to Comments to NDDH Request #7

Discussion of the SCR system supplier's and catalyst vendors' proposals were summarized in the February 11, 2010 response to the NDDH, with additional responses as provided elsewhere in this document.

Responses to Comments to NDDH Request #8

The flue gas-gas reheating equipment temperatures have not been finalized because the process calculations used as a basis of the system design in hypothetical applications of low-dust and tail end SCRs at MRYS are preliminary. The assumptions were summarized in the February 11, 2010 response to the NDDH.

Responses to Comments to NDDH Request #9

Many comments presented by the DOJ's SCR consultant regarding the WE Energies South Oak Creek Units 5, 6, 7, and 8 and PSE&G's Mercer Units 1 and 2 cold-side LDSCR retrofits contain significant errors and other statements that are incorrect and misleading:

- South Oak Creek LDSCRs are not designed for 90% NOx removal efficiencies. Confirmation from the SCR system supplier (Babcock Power)¹⁰⁶ indicates design inlet NOx emissions ranged between 0.15 and 0.22 lb/mmBtu and guaranteed outlet emissions of 0.07 lb/mmBtu. This results in nominal SCR system overall NOx removal efficiencies between 53% and 68%. Even if the worst case amount of untreated gas leakage across the GGH to the reactor inlet is factored in (up to 5%, which is much greater than the 1% leakage guaranteed by the GGH vendor without seal air usage), and a performance margin below 0.07 lb/mmBtu outlet emissions (to 0.065 lb/mmBtu) were applied, the actual reactor NOx removal efficiencies could be around 75%. This is substantially less than the amount claimed by the DOJ's SCR consultant.
- Mercer LDSCRs were not designed for 90% NOx removal efficiencies. The SCR system supplier (Babcock Power) that subsequently worked on the project believes the nominal SCR system overall NOx removal efficiency was 85%¹⁰⁷.
- Mercer boilers are not cyclone-fired as claimed. They are twin-furnace wet bottom (slagging) pulverized coal-fired boilers with high uncontrolled NOx emissions, but which have been previously retrofitted with amine-enhanced selective non-catalytic reduction (AESNCR™) technology¹⁰⁸.

We believe it is inappropriate to compare the capital costs associated with the low-dust SCR installation at Mercer Station, or at South Oak Creek Station, against those developed for the hypothetical applications of low-dust and tail end SCR technologies at MRYS. This is primarily because:

- Control cost effectiveness of alternatives in a BACT analysis is calculated prospectively, i.e. before the selected alternative has been chosen and implemented. This request involves comparing an actual cost amount against an estimated number, which while the latter is sufficient for the purposes of performing a BACT analysis for control cost effectiveness, is not based on similar assumptions of implementation. The Mercer project has been completed and (presumably) all project capital costs should be known. While the South Oak Creek Station LDSCR projects are not completely constructed, we believe all major equipment has been procured and construction contracts substantially underway. The forecast capital costs for South Oak Creek Station LDSCR projects' completion should be fairly close to what will be the actual final amount. The capital costs estimated by Burns & McDonnell for the hypothetical applications of low-dust and tail end SCR technologies at

¹⁰⁶ Telephone conference call between R. Blakley and C. Weilert of B&McD with M. Gialanella, J. Waller, and C. Erickson of Babcock Power on July 22, 2010.

¹⁰⁷ Ibid July 22, 2010.

¹⁰⁸ See Reference number 26.

MRYs are not based on completed final designs and firm bid equipment quotes and installation bids for the SCR systems and auxiliaries. Because actual equipment procurement contracts are often higher in monetary amount than the initial budgetary quotes, the latter not being a “not-to-exceed” amount, we believe that the previous and current response to this NDDH request issue is suitable and sufficient.

- Mercer LDSCRs were implemented due to a Consent Decree (and subsequent amendment) that required installation of “state-of-the-art controls”, including SCR technology, and achieving and maintaining NOx emission rates at Mercer Unit 1 and Unit 2 no greater than 0.100 lb/mmBtu based on 90-day rolling average emission rates¹⁰⁹. This was not a case where a BACT analysis and a BACT determination were required for nitrogen oxide emissions controls, which is what applies to MRYs.

Responses to Comments to NDDH Request #10

Explanation for the selection of natural gas for a flue gas reheat source was provided in the December 11, 2009 response to the NDDH, and the discussion of the determination that Minnkota’s units are boiler-limited was documented in the February 11, 2010 response to the NDDH.

Responses to Comments to NDDH Request #11 a

We reject the DOJ’s SCR consultant’s comments that “B&McD coarsely overestimated the TESCO, for which HTI didn’t offer any specific deactivation rate and exchange frequency”¹¹⁰. Clarification of the catalyst volume for MRYs Unit 2 reactors was documented in the February 11, 2010 response to the NDDH. Haldor Topsoe’s October 2009 proposal primarily focused on catalyst volume, pitch, and composition for reactors sized for a low dust SCR on each MRYs boiler located just downstream of the ESP. Burns & McDonnell assumed the volume of catalyst for a hypothetical application of low dust SCR on each MRYs boiler was also the same for a tail end SCR configuration, based upon statements in Haldor Topsoe’s confidential October 12, 2009 proposal. However, the commenter ignores these statements in HTI’s proposal. We recommend that the NDDH ignore the DOJ’s SCR consultant’s comments for this item. The comments do not reflect or consider the reasons stated in HTI’s October 2009 proposal¹¹¹ for the preliminary design basis and assumptions involved with [estimating the capital and operating/maintenance costs for] retrofitting low-dust and tail end SCRs at MRYs that have been presented earlier in this document and in the November 2009 Supplemental NOx BACT Analysis Study reports.

Responses to Comments to NDDH Request #11 b

¹⁰⁹

¹¹⁰ Ibid Reference number 22, page 39, April 2010.

¹¹¹ Ibid Reference number 5, Appendix D.

Many comments presented by the DOJ's SCR consultant regarding the flue gas reheating equipment process design and impacts using steam on unit electrical energy output for cold-side LDSCR and tail end SCR retrofits contain significant statements that are incorrect and misleading:

- No actual examples are provided by Mr. Hartenstein involving the use of natural gas for flue gas reheating of LD and TESCRs in Europe, which he has repeatedly claimed are typically reheated using steam. Assumptions and comparisons of flue gas reheating equipment process design and impacts using steam on unit electrical energy output are expected to be different than the process design using natural gas, otherwise, why would the EPA and the DOJ's SCR consultant so vigorously argue about Minnkota's choice to use natural gas and its influence on the control cost effectiveness numbers calculated by Burns & McDonnell in the November 2009 Supplemental NOx BACT Analysis Study reports.
- The majority of the commenter's arguments involve the estimated amount of reduction in unit electrical energy outputs from using steam for flue gas reheating in hypothetical applications of low-dust and tail end SCR technologies at MRYS, including using the uncorrected GGH temperature gradient for MRYS Unit 1's LDSCR. We disagree with the commenter's statement that the amount of reduction in unit electrical energy outputs from using steam for flue gas reheating should be the same between LD and TESCRs for the same temperature gradient across the SCR GGH for each unit. This ignores the reality that flue gas is saturated with water at the FGD absorber outlets, which requires more heat to raise the flue gas the same amount of temperature rise as a LDSCR case. While the flue gas temperature is slightly above saturation (increased by the FGD GGH in Minnkota's cases) before entering the SCR GGH in the TESCR cases and so does not necessitate adding the latent heat of water vaporization by the SCR GGH, the higher moisture content of the flue gas from the scrubber will still require more heat to raise its temperature versus a LDSCR case. The amount of SCR flue gas-gas heat exchanger heat transfer and supplemental heat required was calculated by B&McD's SCR process design consultant for each of the four cases (MRYS U1 LD and TESCRs, U2 LD and TESCRs). This was described in the December 11, 2009 response to the NDDH. Unit 1's LDSCR case was subsequently revised in February 2010 and submitted in the February 11, 2010 response and revised February 2010 Unit 1 Supplemental NOx BACT Analysis Study report.
- We also dispute the commenter's statement that SCR operating temperatures and SCR flue gas-gas heat exchanger temperature gradients should be the same for LD versus TESCRs at MRYS. This ignores the reality that flue gas upstream of the FGD absorbers includes many times more sulfur dioxide and is expected to have more sulfur trioxide concentrations than downstream of the scrubber outlets. Acid dewpoint temperatures of the flue gas will be higher before the scrubbers than after. This is the reason why the LDSCR reactor temperatures need to be higher. It was because of the expected commonality of the SCR GGH equipment that the temperature gradients were selected to be

the same for all cases (corrected) of hypothetical applications of low-dust and tail end SCR technologies at MRYS.

- We disagree with the commenter's assumptions involving diverting steam for flue gas reheat not causing an increase in unit heat rate (lower heat to electricity conversion efficiency). Steam used for flue gas reheating must be at sufficient pressure, whether saturated or superheated, to provide a heat source with temperature high enough to be at or above the desired reactor inlet temperature, due to the inefficiency of the steam-to-gas heat exchanger used in the example that the DOJ's SCR consultant provided. Any steam withdrawn from a subcritical boiler's steam drum reduces the amount that is available to go through the superheater sections prior to the main steam piping supplying the steam turbine inlet. While there are other potential uses for this diverted steam, the point of the December 11, 2009 response¹¹² was to explain that steam that would normally flow from the boiler to the steam turbine so that the energy it contains would produce electrical power from the main generator would be reduced in mass flow, and thus gross unit output (MW_g) will decrease. Steam used for dilution air heating or feedwater heating is normally supplied from the steam turbine by extraction, but it does add to the generator's electrical output before being extracted. So there is a heat rate penalty (loss of efficiency in converting heat to electricity) if high pressure steam in any form is used for flue gas reheating.
- We believe there is a possibility that a flue gas reheat steam coil, placed after the main SCR GGH, could become fouled with deposits. This may occur due to pass-through of particulate and moisture during cold unit startups when coal is first being fired and the scrubber is operating (outlet gas is saturated). A period of time before sufficient heat is available from the GGHs and recirculated gas to raise all the metal SCR ductwork in temperature so there will be no acid or vapor condensation could exist when the deposits could form. We doubt that any of the European boilers with TESCRs using steam coils for flue gas reheating have particulate with such sticky characteristics as could occur at MRYS.
- Minnkota and Burns & McDonnell were not asked to calculate control cost effectiveness or substantiate potential impacts on operating costs from steam usage for flue gas reheat associated with LD and TESCRs more than two years ago. The Supplemental MRYS NOx BACT Analysis Study reports were submitted in November, 2009, less than four months after receiving the request letter from the NDDH dated July 15, 2009. A letter request from the NDDH regarding the use of steam from the main boilers for flue gas reheat NDDH's was dated November 25, 2009 and a response was submitted on December 11, 2009. A response to a subsequent letter from the NDDH dated January 11, 2010 was provided on February 12, 2010 that answered the question involving an apparent

¹¹² Ibid Reference number 13, page 4; December 2009.

discrepancy in reheat for MRYS Unit 1's low-dust SCR case in the November 2009 Supplemental MRYS NOx BACT Analysis Study.

- The units at MRYS are boiler-limited. The higher the hourly fuel firing rate, the faster the boilers' fireside surfaces foul with ash and slag deposits. Minnkota has determined through years of experience how to sustain operation at outputs close to maximum continuous ratings before having to shutdown and remove the fireside deposits. Even if they were not boiler-limited, sustained firing of additional fuel for producing the same gross megawatt output as without steam usage for flue gas reheat would create an increase in annual tons of NOx and other emissions, compared with not using steam and not firing harder, even if emissions are controlled at lower lb/mmBtu rates.

Responses to EPA's SCR Cost Analysis

We believe that the EPA's attempt to recalculate the control cost effectiveness analysis improperly oversteps the detailed, site-specific basis and rigorous cost estimating approach that has been provided by Burns & McDonnell and submitted by Minnkota for use by the North Dakota Department of Health's Air Quality Division as the basis for their preliminary determination of Best Available Control Technology for the control of nitrogen oxides emissions from the cyclone boilers firing North Dakota lignite at the Milton R. Young Station. The EPA's interpretation and denials of the valid use of documented assumptions are not consistent within the NSR Manual and its Appendix B for the hypothetical SCR cases in the November 2009 Supplemental NOx BACT Analysis studies for MRYS Unit 1 and Unit 2. The NSR Manual specifically mentions the use of a levelizing cost approach for estimating annual control costs of alternatives in a BACT analysis. The EPA's approach ignores the disclaimer included in its own OAQPS Control Cost Manual chapter for SCR that states it should not be used to estimate costs regarding cases of tail end [and low-dust] SCRs requiring flue gas reheat equipment. The EPA's claims that anhydrous ammonia must be assumed as the only allowed reagent and that use of regenerated catalyst should be assumed are unsubstantiated and unproven.

Summary of Responses to EPA and DOJ's SCR Consultant's Comments

SCR technology is considered technically infeasible by Minnkota for application at MRYS per the October 2006 NOx BACT/BART Analysis Study reports and subsequent submittals in response to comments by the NDDH, EPA, DOJ, and other parties, including the November 2009 Supplemental NOx BACT Analysis Study reports and subsequent responses. We disagree with the EPA's conclusions that the "there is a presumption that SCR is both technically and economically feasible at MRYS" simply because "SCR has been successfully applied worldwide to such a wide variety of sources"¹¹³. We believe that the EPA has incorrectly interpreted the NSR Manual and improperly compared NOx control costs of hypothetically-applied low dust and tail end SCRs on MRYS cyclone boilers firing North Dakota lignite to other emission sources of dissimilar type and ignored the other mitigating circumstances that the NDDH considered before issuing their revised preliminary BACT Determination for the M.R. Young Unit 1 and Unit 2 boilers.

¹¹³ Ibid, Reference number 2, page 29, May 2010*.

Responses to May 2010 National Park Service Comments

We believe that the NPS's attempt to recalculate the control cost effectiveness analysis improperly oversteps the detailed, site-specific basis and rigorous cost estimating approach that has been provided by Burns & McDonnell and submitted by Minnkota for use by the North Dakota Department of Health's Air Quality Division as the basis for their preliminary determination of Best Available Control Technology for the control of nitrogen oxides emissions from the cyclone boilers firing North Dakota lignite at the Milton R. Young Station. The NPS's approach ignores the disclaimer included in the EPA's OAQPS Control Cost Manual chapter for SCRs that it should not be used to estimate costs regarding cases of low-dust and tail end SCRs requiring flue gas reheat equipment. There are other assumptions made by the NPS for their control cost analysis that we disagree with, essentially for the same reasons as stated in our responses to the EPA's May 2010 comments. It should also be noted that MRYS NO_x BACT Analysis alternatives' control costs were estimated prospectively with calendar year 2006 basis, including those involving hypothetical applications of low-dust and tail end SCR technologies. We reject the NPS's NO_x control costs effectiveness analysis for MRYS for many reasons not repeated here, particularly because it makes numerous assumptions that are inconsistent with the MRYS NO_x BACT Analyses for non-SCR alternatives and does not consider or address incremental control costs in accordance with the NSR Manual.

We also disagree with the National Park's Service calculations of baseline NO_x emissions and annual reductions claimed to be in accordance with the EPA's NSR Manual. The NSR Manual states "Annual "potential" emission projections are calculated using the source's maximum design capacity and full year round operation (8760 hours)...[and] emissions estimates used for the purpose of calculating and comparing cost effectiveness of a control option are based on a different approach"¹¹⁴...For cost-effectiveness analysis, the NSR Manual also states: "Estimating realistic upper-bound case scenario does not mean that the source operates in an absolute worst case manner all the time. For example, in developing a realistic upper-bound case, baseline emissions calculations can also consider inherent physical or operational constraints on the source. Such constraints should accurately reflect the true upper boundary of the source's ability to physically operate and the applicant should submit documentation to verify these constraints"¹¹⁵.

On an annual basis, historical data for MRYS Unit 1 and Unit 2 boilers used in the NO_x BACT analyses are considered a valid representation of the annual NO_x tons to be assumed for the pre-control annual baselines for the purpose of calculating cost effectiveness of control options. It is unrealistic to assume that these boilers would be capable of operating at the maximum hourly heat input ratings continuously with allowable annual average unit emission rates for 8,760 hours per year for the estimation of control cost effectiveness of

¹¹⁴ Ibid Reference number 10, page B.23, October 1990.

¹¹⁵ Ibid, page B.37, October 1990.

NO_x control options. It should be recognized that the NO_x control cost analysis for MRYS Unit 1 and Unit 2 boilers has a different annual pre-control and post-control basis than what is used for visibility impairment impact analysis for BART.

The fact that the estimated site-specific total installed capital costs of the hypothetical applications of SCRs in Minnkota's Supplemental NO_x BACT Analysis studies do not correspond with NPS's assumptions and use of cost ratios to develop their estimates is not a result of Burns & McDonnell improperly accounting for design, procurement, and installation conditions. We believe it is a failure on the NPS's part to recognize the limitations of their methods and use of the OAQPS Control Cost Manual with respect to accurately estimating costs of these technologies on a relevant site-specific basis. NPS has ignored the previously-stated disclaimer not to use the referenced EPA OAQPS Control Cost Manual report because of its inadequacies.

The NPS believes that NDDH should have considered Regenerative Selective Catalytic Reduction technology for potential application at MRYS on Unit 1 and Unit 2 boilers. We disagree that this form of low-dust cold-side SCR system is applicable and suitable for NO_x emissions control of the units Minnkota operates.

The system supplier (Babcock Power Inc.) markets RSCR[®] technology to reduce NO_x emissions from relatively small biomass (wood)-fired and industrial boilers, waste-to-energy furnaces, and other process applications which lack sufficient space for conventional hot-side high dust SCR and/or need to avoid exposure of the catalyst to untreated emissions¹¹⁶. Typical installations have been on wood-fired boilers between 15 and 54 MW equivalent output, reducing NO_x emissions from 0.25-0.28 lb/mmBtu to below 0.065-0.075 lb/mmBtu, for 70-85% control. There have been no known installations on small, medium, or large-scale utility coal-fired boilers. Even though they are called "tail-end" SCR, typical inlet flue gas temperatures are 200-350°F. As far as we can discern, they have not been applied downstream of any boilers with wet or dry flue gas desulfurization systems. Particulate and gaseous emissions from MRYS cyclone boilers firing North Dakota lignite contain sulfur compounds and very fine sodium aerosols, which have been previously described in detail and provided by Minnkota to NDDH. Babcock Power did not suggest to Burns & McDonnell that such a system be considered as an alternate approach for Minnkota when BPI was asked to provide conceptual designs and indicative pricing for MRYS low-dust and tail-end SCRs. Likewise, there is no publicly-available information discovered that indicates that Babcock Power, supplying the low-dust SCRs at South Oak Creek plant Units 5-8 for Wisconsin Electric Power Company, suggested RSCR[®] technology be applied on these referenced medium-sized coal-fired utility boilers. There is insufficient evidence that RSCR[®] technology is applicable and suitable for NO_x emissions control of the MRYS Unit 1 and Unit 2

¹¹⁶ See Reference number 28, September, 2008.

boilers. Further consideration of RSCR[®] technology for the MRYS NO_x BACT and BART analyses is unwarranted.

Responses to January 2010 National Parks Conservation Association Comments

We reject the NPCA's arguments¹¹⁷ regarding NDDH's Regional Haze State Implementation Plan (RH SIP) for control of NO_x emissions for MRYS for many reasons previously provided and not repeated in their entirety here. A summary of the pertinent major reasons include:

- We continue to agree with NDDH that hot side, high dust SCR (HDSCRs) are technically infeasible at MRYS. The NPCA fails to recognize that technical issues which include demonstrated failure of the pilot-scale SCR slip stream test at Coyote station, excessive boiler flue gas temperatures and severe flue gas characteristics preclude the successful application of HD SCR at MRYS. Catalyst vendors require flue gas temperatures to be within a range that their catalyst can withstand and perform effectively for extended periods. Without assurances from SCR system suppliers, i.e. boiler original equipment manufacturers, that the MRYS boiler's extreme flue gas temperature range can be successfully resolved without impacting the required lignite drying systems' performance and reliability, and how much that will cost, there is great uncertainty that hot-side, high dust SCR can be successfully applied and operated even without the added questions of catalyst deactivation, fouling, plugging, and other problems. BACT and BART do not mean "experimental development of air pollution control technologies' design that must be performed as a prerequisite for determining the probable success or potential failure of the subject technology to work successfully".
- NPCA's statements that catalyst vendors bear the risk of failure¹¹⁸ is misleading – the utility implementing the SCR project pays for potential risk of the vendor to fail to deliver a product usable in the SCR installation by spending sums of money much greater than the initial catalyst cost. The owner of the plant ultimately assumes the business and environmental compliance risks to operate and maintain such air pollution control systems long after the contractual guarantees and warranty periods expire, which are much shorter than the expected remaining life of the equipment or plant.
- NPCA's statements that the catalyst used at the Coyote station pilot-scale SCR slip stream test are incorrect that "while it was *supposedly cleaned* [emphasis added] between tests"...it is undisputed that it was not new or fresh catalyst"¹¹⁹. EERC used the same pilot-scale slip stream test apparatus with the same vendor's type, pitch, and formulation of catalyst at the Baldwin station and at Coyote station, but it is indisputable that fresh catalyst was, in fact, used at the Coyote station pilot SCR test.

¹¹⁷ Ibid Reference number 4, January 2010*.

¹¹⁸ Ibid, page 24, January 2010*.

¹¹⁹ Ibid, page 24, January 2010*.

It is an incorrect interpretation of EERC's technical paper¹²⁰, and, along with NPCA's comments regarding pilot SCR test catalyst selection and results of the Coyote and Baldwin pilot-scale slip stream SCR tests, does not accurately reflect subsequent responses on this issue previously submitted to the NDDH and EPA¹²¹.

- NPCA's comments on sodium, catalyst vendor guarantees, and control cost details¹²² do not accurately reflect subsequent responses on this issue previously submitted to the NDDH and EPA¹²³.

¹²⁰ See Reference number 24, October 2005.

¹²¹ See Reference number 23, 2007-2009 and Reference number 16, February and April, 2010*.

¹²² Ibid Reference number 4; pages 24-27, January 2010.

¹²³ Ibid Reference number 238, 2007-2010*.

REFERENCES

1. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Comments on Preliminary BACT Determination*, dated May 12, 2010.
2. United States Environmental Protection Agency Region 8 letter from Andrew M. Gaydosh to Mr. Terry O'Clair, Director, Division of Air Quality, North Dakota Department of Health, *Re: EPA's Comments on the North Dakota Department of Health's April 2010 Draft BACT Determination for NOx for the Milton R. Young Station*, date stamped May 10, 2010, with enclosures, including a "Request for Proposal for Conceptual SCR Catalyst Design for a Low-Dust and Tail-End System, February 2010" as part of Enclosure 15.
3. National Park Service Policy, Planning and Permit Review Branch from John Bunyak, Chief, Terry L. O'Clair, P.E., Director, Division of Air Quality, North Dakota Department of Health, Environmental Health Section, *Re: NPS comments regarding the proposed [North Dakota Department of Health's April 2010 Draft] Best Available Control Technology (BACT) Determinations [for NOx] for the Milton R. Young Station (MRYS)*, dated May 10, 2010.
4. National Parks Conservation Association letter to Terry L. O'Clair, Director, Division of Air Quality, North Dakota Department of Health, *Re: Comments on North Dakota's Regional Haze State Implementation Plan*, dated January 8, 2010.
5. North Dakota Department of Health, Environmental Health Section, Division of Air Quality, "Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2", posted at the NDDH website <http://www.ndhealth.gov/aq/Dockets/Minnkota/BACT%20April%202010/BACT%20Analysis/BACT%20Analysis%2004-10.pdf>, dated April, 2010. Includes redacted catalyst vendor proposals posted at the NDDH website under Appendix D of the Minnkota Power Cooperative – Preliminary BACT Determination (April 2010) in the public notices > <http://www.ndhealth.gov/AQ/Dockets/Minnkota/BACT%20April%202010/Appendix%20D/Haldor%20and%20CERAM%20Statements.pdf>. This followed "ND Department of Health, Division of Air Quality Preliminary Best Available Control Technology Determination for Control of Nitrogen Oxides for M.R. Young Station Units 1 and 2, June 2008, released for public comment June 3, 2008".
6. North Dakota Department of Health, Environmental Health Section, Division of Air Quality, "Final Regional Haze State Implementation Plan Revision", and related documents pertaining to Department BART Determinations in Appendix B.4 for M.R. Young, and Minnkota SCR Technical Feasibility in Appendix B.6, posted at the NDDH website <http://www.ndhealth.gov/AQ/RegionalHaze/>, dated November 25, 2009.
7. "BACT Analysis Study for Milton R. Young Station Unit 1 Minnkota Power Cooperative, Inc." and a separate "BACT Analysis Study for Milton R. Young Station Unit 2 Square Butte Electric Cooperative, October 2006", included with the "BART DETERMINATION STUDY for Milton R. Young Station Unit 1 and 2 Minnkota Power Cooperative, Inc. Final Report, October 2006".

8. Consent Decree filed in the United States District Court For The District Of North Dakota, United States Of America and State Of North Dakota, Plaintiffs, v. Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Defendants, Civil Action No.1:06-CV-034, filed April 24, 2006.
9. *"NO_x Best Available Control Technology Analysis Study – Supplemental Report for Milton R. Young Station Unit 1 for Minnkota Power Cooperative, Inc., November, 2009; and a separate NO_x BACT Analysis Study – Supplemental Report for Milton R. Young Station Unit 2 for Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, November 2009"*, November 12, 2009.
10. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: Milton R. Young Station BACT Determination*, dated July 15, 2009, and *Re: Request for Time Extension*, dated August 7, 2009.
11. EPA New Source Review Workshop Manual, Prevention of Significant Deterioration and Nonattainment Area Permitting, Draft October 1990 (The "NSR Manual").
12. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: BACT Cost Estimate*, dated November 25, 2009.
13. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Responses to NDDH Request NO_x BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility"*, December 11, 2009.
14. Burns & McDonnell presentation to North Dakota Department of Health, Air Quality Division *"Milton R. Young Supplemental NO_x BACT Analysis Study Review with SCR Cost Estimate Study Summary"* December 21, 2009.
15. North Dakota Department of Health, Environmental Health Section, Division of Air Quality letter by Terry L. O'Clair, P.E. to John Graves, Minnkota Power Cooperative, *Re: SCR Cost Estimate*, January 11, 2010.
16. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Followup Responses to Presentation and NDDH Request for Additional Information, Supplemental NO_x BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Economic Feasibility"*, February 11, 2010; and March 31, 2010 correction to revised CERAM catalyst budgetary proposal dated October 13, 2009. (There was a typographical error in the fill-in data sheets regarding the fly ash concentration in the catalyst design for the Unit 1 low dust arrangement; all other aspects of the proposal remained unchanged). This document was submitted to the NDDH and claimed as confidential in accordance with Air Pollution Control Rules for the State of North Dakota at 33-15-01-16. See February 2010 response, page 2, for additional details.
17. EPA Office of Air Quality Planning and Standards (OAQPS) Air Pollution Control Cost Manual – Sixth Edition (EPA/452/B-02-001), January 2002, Section 1 and Section 4.2 Chapter 2.

18. *"Current Capital Cost and Cost-Effectiveness of Power Plant Emissions Control Technologies"*, J. Edward Cichanowicz, Prepared for Utility Air Regulatory Group, June 2007.
19. United States Environmental Protection Agency Region 8 June 2010 emails with attachments to Tom Bachman, Division of Air Quality, North Dakota Department of Health:
 - a. CERAM Environmental, Inc. June 4, 2010 email from Greg Holscher to Jeff Kodish, USEPA, with attachment: SCR Catalyst Budgetary Proposal Support for Low Dust and Tail End Study, CERAM Proposal No. GH100315-2 (Confidential), dated March 31, 2010.
 - b. Haldor Topsoe, Inc. June 17, 2010 email from Nathan White to Jeff Kodish, USEPA, with attachment: Haldor Topsoe Low Dust and Tail End Systems.pdf (confidential quotation, 10-6089-R1), and Haldor Topsoe Catalyst Management Plan.pdf (confidential), dated March 20, 2010.
 - c. Johnson Matthey Catalysts LLC June 16, 2010 email from Cindy Khalaf to Jeff Kodish, USEPA, with attachment: Budgetary Proposal JMC for LDSCR and TESCR.pdf (confidential proposal 71779), dated March 12, 2010.
20. CERAM Environmental, Inc. letter by Noel Rosha to Luther Kvernen, Minnkota Power Cooperative, Inc., Re: Milton R. Young Station SCR Performance Guarantees, June 11, 2010. (See attachments)
21. Haldor Topsoe, Inc. letter by Wayne Jones to Robert Blakley, Burns & McDonnell, Re: Evonik RFP SCR Performance Guarantees, July 27, 2010. (See attachments)
22. *"Report of Hans Hartenstein: On North Dakota Department of Health's April 10, 2010 BACT Determination for Minnkota's M. R. Young Station, Expert Report of Hans Hartenstein, On Behalf Of The United States Department Of Justice"*, dated April 2010.
23.
 - a. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses To EPA Comments NOx BACT Analysis Study Milton R. Young Station Unit 1 and Unit 2 Regarding SCR Technical Feasibility"* March 15, 2007 (re: U.S. EPA Region 8 letter January 8, 2007); and
 - b. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative, Responses To NDDH and EPA Comments Regarding SCR Technical Feasibility and Non-SCR Concerns Milton R. Young Station Unit 1 and Unit 2 NOx BACT Analysis Study"* April 18, 2007 (re: NDDH letter February 1, 2007 including U.S. EPA Region 8 letter January 26, 2007); and
 - c. Burns & McDonnell and Energy & Environmental Research Center (EERC) presentation, *"Summary of Responses to EPA/DOH Questions on Minnkota Power's NOx BACT Analysis for Milton R. Young Units 1 & 2, to North Dakota Department of Health, Environmental Health Section, Division of Air Quality, and United States Environmental Protection Agency, May 23, 2007"*); and
 - d. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Comment and Response To EPA Region 8's October 4, 2007 Comment on NDDH BACT Determination at Milton R. Young Station"* November, 2007 (re: U.S. EPA Region 8 letter October 4, 2007); and
 - e. *"Minnkota Power Cooperative, Inc. and Square Butte Electric Cooperative Additional Information and Discussion of Vendor Responses on SCR Technical*

Feasibility North Dakota's NOx BACT Determination for Milton R. Young Station Units 1 & 2, May 8, 2008"; and

f. *"Comments and Responses to NDDH Regarding U.S. EPA Region 8's July 31, 2008 Comments and Plains Justice July 30, 2008 Comments on NDDH Preliminary NOx BACT Determination for Milton R. Young Station (MRYS)"* September 22, 2008 (re: U.S. EPA Region 8 letter July 31, 2008); and

g. Burns & McDonnell, University of North Dakota, and Fuel Tech, *"Responses to Hans Hartenstein's October 2008 Remarks to September 22, 2008 Comments and Responses on NDDH Preliminary NOx BACT Determination for Milton R. Young Station (MRYS)"*, November 17, 2008 (re: U.S. EPA Region 8 letter October 17, 2008); and

h. *"Supplemental Information for Consideration Regarding NOx BACT for M.R. Young Units 1 and 2: Technical Feasibility Issues for TESCO or LDSCR Retrofit"*, February 20, 2009 revised March 2, 2009; and

i. Burns & McDonnell and Energy & Environmental Research Center (EERC) presentation to NDDH *"Supplemental Information for Consideration Regarding NOx BACT for M.R. Young Units 1 and 2: Technical Feasibility Issues for TESCO or LDSCR Retrofit"* March 2, 2009.

24. *"Ash Impacts on SCR Catalyst Performance"*, prepared by Steven A. Benson, Ph.D. Energy & Environmental Research Center, University of North Dakota, October 2005.
25. Kling, A.; Andersson, C.; Myringer, A.; Eskilsson, D.; Jaras, S.G., *Alkali Deactivation of High-Dust SCR Catalysts Used for NOx Reduction Exposed to Flue Gas from 100-MW-Scale Biofuel and Peat Fired Boilers: Influence of Flue Gas Composition*. Applied Catalysis B: Environmental 2007, 69, 240-251.
26. *"First Commercial Installation of Amine Enhanced Fuel Lean Gas Reburn on Units 1 and 2 at Public Service Electric & Gas Mercer Station"*, Andres. F. Gomez, Alexander S. Dainoff, John H. O'Leary, and Robert A. Schrecengost; White Paper, Selective Non-Catalytic Reduction (SNCR) for Controlled NOx Emissions, Institute of Clean Air Companies, Inc., May 2000.
27. "PSEG Fossil L.L.C. Fact Sheet", available at <http://www.epa.gov/compliance/resources/cases/civil/caa/psegllc-fcsht-061130.html> accessed on 12/17/2009.
28. "Babcock Power Inc. Overview for WPCA/Duke Seminar", Craig Peterson and Tony Licata, Babcock Power Inc., September 4, 2008, downloaded June 9, 2010 from Worldwide Pollution Control Association's website at: http://wpca.info/pdf/presentations/Duke_Sept2008/WPCA_Duke_2008_Cofiring_Biomass_Tony_Licata.pdf.

ATTACHMENTS:

1. CERAM Environmental, Inc. letter by Noel Rosha to Luther Kvernén, Minnkota Power Cooperative, Inc., Re: Milton R. Young Station SCR Performance Guarantees, June 11, 2010.
2. Haldor Topsoe, Inc. letter by Wayne Jones to Robert Blakley, Burns & McDonnell., Re: Evonik RFP SCR Performance Guarantees, July 27, 2010.

CERAM

ENVIRONMENTAL, INC.

CERAM Environmental, Inc.
Porzellanfabrik Frauenthal GmbH

Minnkota Power Cooperative, Inc.

Attn. Mr. Luther Kvernen
1822 Mill Road
PO Box 13200
Grand Forks, ND 58208-3200

June 11, 2010

Milton R. Young Station SCR Performance Guarantees

Dear Mr. Kvernen:

On March 31, 2010 CERAM Environmental, Inc. (CERAM) submitted a budgetary proposal (CERAM Proposal GH100315-2) to Evonik Energy Services, LLC (Evonik) to support a conceptual design study project regarding both a low dust and/or tail end SCR application for *unnamed* coal fired units similar to the size of the Milton R. Young station Units 1 and 2. Subsequently we received a request from Evonik that portions of our March 31, 2010 budgetary proposal be released from confidentiality in order to submit the information to the North Dakota Department of Health (NDDH).

As part of our budgetary proposal (GH100315-2) we offered both initial (Test A) and end of life (Test B) catalyst guarantees for NO_x reduction, ammonia slip, SO₂ to SO₃ conversion rate, and pressure drop. This is in contrast to the SCR catalyst proposal we submitted to Minnkota on October 13, 2009 (CERAM Proposal NR090911-2) in which we only provided initial Test A performance guarantees, and recommended a catalyst pilot testing program to characterize the M.R. Young fuel impacts on SCR catalyst in order to provide end of life guarantees.

Please note that although the requests from Evonik and Minnkota were similar, there were distinct differences in the RFP documents. The key differences are as follows:

- The range of fuel analysis provided by Evonik was not as detailed as that provided by Minnkota, and considered a lower maximum range of key constituents that can contribute to catalyst poisoning. For example the Evonik specification listed the maximum sodium content to be significantly less than the Minnkota specification. Sodium is a significant catalyst poison that must be considered for the purpose of guarantees. CERAM must consider the full range of potential coals when supplying catalyst performance guarantees.
- Minnkota submitted with the RFP the entire study performed by Microbeam Technologies, Inc (MTI) titled *Assessment of Particulate Characteristics Upstream and Downstream of ESP and Wet FGD*. This study included detailed flue gas characterization including details on particle size distribution, particle concentrations, and soluble sodium constituents in the flue gas.

7304 W. 130th Street Suite 140 • Overland Park, Kansas 66213

Tel: (913) 239-9896 • Fax: (913) 239-9821

Minnkota Power
Mr. Kvernén

June 11, 2010
Page 2

- Minnkota submitted with the RFP the final report titled *Impact of Lignite Properties on Powerspan's NOx Oxidation System*. The report outlined the impacts of the North Dakota Lignite flue gas and fly ash on Powerspan's multi-pollutant control system called electrocatalytic oxidation (ECO) technology, specifically the sodium-rich aerosols and small ash particles which accumulated and became bonded to the surface of the silica electrodes used in this technology.

CERAM would not have included end of life (Test B) performance guarantees in our budgetary proposal to Evonik had their RFP included the same level of detail that was provided in the Minnkota RFP documents, but would have again recommended a catalyst pilot test program to characterize the impacts of firing North Dakota Lignite coal upstream of SCR catalyst. Should you have any questions or need further information please contact me via e-mail (noel.roscha@ceram-usa.com) or at 913-239-9896.

Yours sincerely,
CERAM Environmental, Inc.



Noel Rosha
Senior Applications Engineer

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Houston, Texas 77058
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Tel: (281) 228-5000
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July 27, 2010

Mr. Robert Blakley, P.E.
Associate Project Engineer
Energy Group
9400 Ward Parkway
Kansas City, MO 64114

Dear Robert:

This letter is in response to questions raised by Burns and McDonnell and EPA concerning HTI's recent catalyst Quotation 10-6089 and 10-6089-R1 to Evonik Industries.

In February 2010, HTI received a Request for Quotation from Hans Hartenstein of Evonik Industries. The RFQ was for the supply of SCR catalyst for a coal fired unit. The proposal requested a quote for both a low-dust SCR and a tail-end SCR. The RFQ was given to one of newer associates to review and to provide the requested quotations.

The RFQ provided very little detail about the unit. No unit name or operating company was provided. No proximate or ultimate fuel analysis was provided; nor was there any ash analysis provided. In the RFQ, no mention was made that in fact this unit was firing North Dakota lignite. Actually very little operating data was provided. This included limited information with regard to flue gas chemical makeup. In retrospect, HTI should have requested additional detailed information about the proposed fuel from Evonik.

The quotation that was provided was based on a typical low arsenic eastern bituminous coal. No consideration was made for the fuel being anything else other than eastern bituminous. The typical guarantees that we provide for eastern bituminous fired boilers were provided in this quotation. These guarantees would not have been provided if HTI had known that the fuel fired on this unit is North Dakota lignite.

HTI currently has one of the first SCR's on a unit firing Texas lignite, where HTI provided a full 3 year catalyst life guarantee along with typical NOx removal effects, ammonia slip, SO₂ Oxidation rates, and pressure drop guarantees. Performance of this SCR has been excellent since start-up. HTI also has the majority of the biomass fired applications in the U.S. and the majority of the IGCC applications in the world. All of these are new and very challenging projects which push the technology to the next level.

HTI does not avoid challenging applications, but we do review the technical as well as financial risks associated with each project. If the risk level is too high then we may choose not to participate in the project or only provide catalyst without performance guarantees.

If you have any questions, please do not hesitate to call me at 281-228-5136.

Sincerely,

HALDOR TOPSOE, INC.



Wayne S. Jones
Sales Manager, Power Generation
SCR/DeNOx Catalyst & Technology

WSJ/gad/33/Jul2010